BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2021-88-E - ORDER NO. 2022-329

MAY 2, 2022

IN RE: Dominion Energy South Carolina, Incorporated's 2021 Avoided Cost Proceeding Pursuant to S.C. Code Ann. Section 58-41-20(A)	))))	ORDER ESTABLISHING AVOIDED COSTS AND RELATED ISSUES

I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina ("Commission") pursuant to the requirements of S.C. Code Ann. § 58-41-20, which was enacted into law by Act No. 62 ("Act 62") of 2019 and became effective on May 16, 2019. S.C. Code Ann. § 58-41-20(A) directs the Commission to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements ("Form PPAs"), commitment to sell forms, and any other terms or conditions necessary to implement this section." S.C. Code Ann. § 58-41-20 further requires that the Commission "at least once every twenty-four months . . . approve each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section." Consistent with these statutory provisions, on March 10, 2021, the Commission established the above-captioned docket for the purpose of evaluating and establishing Dominion Energy South Carolina, Inc.'s ("DESC" or the

"Company") standard offer, avoided cost methodologies, Form PPAs, commitment to sell forms, and any other terms or conditions necessary to implement the requirements of S.C. Code Ann. § 58-41-20.

DESC's current standard offer, avoided cost methodologies, Form PPAs, commitment to sell forms, and other appropriate terms and conditions were approved by the Commission in Order No. 2019-847, dated December 9, 2019, and Order No. 2020-244, dated March 24, 2020, issued in Docket No. 2019-184-E, the first proceeding conducted under section 58-41-20(A).

II. PROCEDURAL HISTORY

On March 10, 2021, the Commission opened this docket as referenced in Order No. 2021-166. DESC, pursuant to Order No. 2021-166, filed its Application on April 22, 2021, pursuant to S.C. Code Ann. Section 58-41-20(A), seeking the Commission's approval of its Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and All other Appropriate Terms and Conditions regarding avoided costs.

On April 30, 2021, the Commission Clerk's Office filed a Notice of Filing and Hearing and Prefile Testimony Deadlines, setting forth deadlines and advising all persons who wished to participate as a Party of Record of the manner and time in which to submit filings. DESC filed affidavits attesting to publication of the Notice on May 24, 2021.

Petitions to Intervene were received from: Johnson Development Associates, Inc. ("JDA"); the Carolinas Clean Energy Business Association ("CCEBA"); the South Carolina Department of Consumer Affairs ("DCA"); the South Carolina Coastal

Conservation League and Southern Alliance for Clean Energy (collectively, "CCL/SACE"); and Pine Gate Renewables, LLC ("Pine Gate"). DESC did not oppose the Petitions to Intervene, and no other parties sought to intervene in this proceeding. The Commission granted all Petitions to Intervene. The South Carolina Office of Regulatory Staff ("ORS") is also a party of record pursuant to S.C. Code Ann. § 58-4-10(B).

DCA filed a Motion for Commission to Review the Sufficiency of DESC's Application on May 12, 2021. CCL/SACE and CCEBA filed letters in support of DCA's Motion. The Commission granted DCA's Motion by Order No. 2021-384, dated May 26, 2021, which directed DESC to file an Amended Application by June 7, 2021. DESC filed its Amended Application on that date and a Second Amended Application on June 25, 2021.

DESC filed its Direct Testimony and Exhibit(s) on June 29, 2021. After motions by CCEBA, the Commission issued Order No. 2021-504 on July 21, 2021, which set new filing deadlines for ORS/Intervenor prefiled direct testimony, rebuttal testimony, and surrebuttal testimony. The Order also denied a Motion to Continue the hearing. Subsequently, the parties prefiled testimony and exhibits in compliance with the Commission Order and filed certain corrected and revised versions of the same.

S.C. Code Ann. Section 58-4-20(I) authorizes the Commission to retain a third-party consultant to evaluate avoided cost rates, methodologies, terms, calculations, and conditions and states the Commission "shall engage, for each utility, a qualified independent third party to submit a report that includes the third party's independently derived conclusions as to that third party's opinion of each utility's calculation of avoided costs for purposes of proceedings conducted pursuant to this section." After issuing multiple Requests for Proposals, the Commission retained London Economics International, LLC ("LEI") and issued a scope of work and procedural dates, including a due date of September 16, 2021, for LEI's report, a deadline of October 5, 2021, for parties to conduct discovery, and a hearing starting on October 6, 2021, for LEI's testimony and cross-examination followed by Commissioner questions. *See* Order No. 2021-520. The Commission subsequently amended the schedule to allow parties to submit responsive testimony to the LEI report by October 8, 2021, and rescheduled the hearing to start on October 11, 2021. *See* Order No. 2021-565.

An evidentiary merits hearing was held virtually from August 18, 2021, through August 25, 2021, at which time the prefiled direct, rebuttal, and surrebuttal testimonies of witnesses for DESC, ORS, CCEBA, and CCL/SACE were presented into evidence. The Honorable Justin T. Williams, Chairman, presided at the hearing. DESC was represented by K. Chad Burgess, Esquire, Matthew W. Gissendanner, Esquire, Mitchell Willoughby, Esquire, and Tracey C. Green, Esquire. JDA was represented by Weston Adams, III, Esquire, and Courtney E. Walsh, Esquire. CCEBA was represented by Richard L. Whitt, Esquire, and John D. Burns, Esquire. CCL/SACE was represented by Kate Lee Mixson, Esquire, and Emma C. Clancy, Esquire. Pine Gate was represented by Richard L. Whitt, Esquire, and J. Blanding Holman, Esquire. DCA was represented by Roger P. Hall, Esquire, Carri Grube Lybarker, Esquire, and Connor J. Parker, Esquire. ORS was represented by Christopher M. Huber, Esquire, and Alexander W. Knowles, Esquire.

During the hearing, the Chairman granted a motion of CCEBA for additional cross-examination of DESC witness Peter David and for leave to file Supplemental Surrebuttal Testimony of CCEBA witness Ed Burgess in response to revisions witness David made from the stand to his prefiled rebuttal testimony.

LEI filed its report on September 17, 2021, and also filed a corrected report on September 22, 2021. CCEBA filed the Supplemental, Surrebuttal Testimony of Ed Burgess on October 5, 2021. On October 8, 2021, DESC filed the Responsive Testimony of Eric H. Bell, Peter B. David, John E. Folsom, Jr., Daniel F. Kassis, and James W. Neely; CCEBA filed the Responsive Testimony and Exhibit of Ed Burgess; and CCL/SACE filed Responsive Testimony from Kenneth Sercy.

The Commission held an additional hearing on October 11, 2021 through October 13, 2021, and heard additional cross-examination testimony of DESC witness David. The Commission also heard the Supplemental Surrebuttal Testimony of CCEBA witness Burgess; LEI presented its report and answered questions from the parties and the Commission; and the Commission heard the Responsive Testimony of DESC and intervenor witnesses to LEI's report. At the October hearing, the Honorable Florence P. Belser, Vice Chairman, presided. DESC was represented by K. Chad Burgess, Esquire, Matthew W. Gissendanner, Esquire, Mitchell Willoughby, Esquire, and Tracey C. Green, Esquire. JDA was represented by Weston Adams, III, Esquire, and Courtney E. Walsh, Esquire. CCEBA was represented by Richard L. Whitt, Esquire, and John D. Burns, Esquire. CCL/SACE was represented by Emma C. Clancy, Esquire. Pine Gate was represented by Richard L. Whitt, Esquire, and J. Blanding Holman, Esquire. DCA was represented by Roger P. Hall, Esquire, and Connor J. Parker, Esquire. ORS was represented by Christopher M. Huber, Esquire, and Alexander W. Knowles, Esquire. LEI was not represented by counsel in this proceeding; however, A. J. Goulding testified on behalf of LEI regarding the LEI Report.

III. STATUTORY LAW

These proceedings arise from Act 62 which pertains to a range of issues related to the integration of renewable energy generation and utility resource planning.

Under Act 62,

> The commission is directed to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The commission also is directed to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state-specific impacts unique to South Carolina which are brought about by the consequences of this act.

S. C. Code Ann. § 58-41-05 (Supp. 2021).

With respect to avoided cost, S.C. Code Ann. Section 58-41-20(A) instructs that:

> . . . . Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public.

S. C. Code Ann. § 58-41-20 (A) (Supp. 2021).

Act 62 further requires that:

> (B) In implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources by ensuring that:
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> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
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> (2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
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> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility.

S. C. Code Ann. § 58-41-20 (B) (Supp. 2021).

IV. ACT 62 DOCUMENTS

Although these form documents, Standard Offers, Form Power Purchase Agreements and Notices of Commitment, discussed in this Order are addressed by Act 62, they do not represent the sole means by which qualifying facilities ("QFs") can sell power to DESC under PURPA. Both PURPA and Act 62 expressly acknowledge that QFs and DESC can negotiate mutually agreeable terms and conditions that differ from the Form

PPA and Standard Offer contracts approved in this docket. S.C. Code Ann. § 58-41-20(A); 18 C.F.R. § 292.301(b).

A standard offer (the "Standard Offer") is defined by S.C. Code Ann. § 58-41-10(15):

> "Standard offer" means the avoided cost rates, power purchase agreement, and terms and conditions approved by the commission and applicable to purchases of energy and capacity by electrical utilities as provided in this chapter from small power producers up to two megawatts AC in size.

Stated differently, a Standard Offer is a PPA that contains an avoided cost rate paid to eligible QFs that are 2 MW in size or smaller. Additionally, the Standard Offer contract sets the terms and conditions and allows any qualifying "small power producer," as defined by S.C. Code Ann. § 58-41-10(14), to contract with the utility to supply electricity at established rates without the need to negotiate individual contracts. The Standard Offer; therefore, establishes set prices, terms, and conditions, and is not negotiated by DESC or the eligible QF. It is intended to address the concern that the costs of negotiating and administering individually negotiated contracts could render smaller projects non-viable.

A Form PPA is similar to a Standard Offer, except that, pursuant to S.C. Code Ann. § 58-41-20(A), it is for use for qualifying small power production facilities that are not eligible for the Standard Offer, i.e., QF facilities that are greater than 2 MW and up to 80 MW in size. The statute also requires that these PPAs contain provisions for force majeure, indemnification, choice of venue, confidentiality, and other such terms. However, the PPA is not determinative of the price or duration of the contract. These issues are to be separately negotiated by DESC and the applicable QF and "may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."[1] As proposed by DESC, the terms and conditions for the Standard Offer and the Form PPA are similar, since the potential impacts to DESC's system and its customers from projects 2 MW or less in size can be comparable to those that exceed 2 MW.

Act 62 also states that QFs "have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the [PPA] then in effect by delivering an executed notice of commitment to sell form to the electrical utility."[2] This standard notice of commitment to sell form ("NOC Form") is required to provide the QF a reasonable period of time from its submittal of the form to execute a PPA, but shall not require a QF, "as a condition of preserving the pricing and terms and conditions established by its submittal of an executed [NOC Form] to the electrical utility, . . . to execute a [PPA] prior to receipt of a final interconnection agreement from the electrical utility."[3]

V. EVIDENCE OF RECORD AND RESULTING FINDINGS OF FACT

A. Difference in Revenue Requirements Methodology

As stated by DESC witness Neely, the Difference in Revenue Requirements ('DRR') methodology to calculate avoided costs involves calculating the revenue requirements between a base case and a change case.[4] The base case is defined by DESC's existing and future fleet of generators and the hourly load profile to be served by these

[1] S.C. Code Ann. § 58-41-20(B)(3).
[2] S.C. Code Ann. § 58-41-20(D).
[3] Id.
[4] Tr. Vol. 2 p. 46.6, lines 8-14.

generators, as well as the solar facilities with which DESC has executed PPAs.[5] The change case is the same as the base case except that a zero-cost purchase transaction is modeled after assuming the addition of an incremental amount of QF energy to DESC's system.[6] For the avoided energy cost determination, DESC uses a computer program called PLEXOS, which models the commitment and dispatch of generating units to serve load hour by hour, makes two runs, and estimates the production costs and benefits that result from the purchase transaction.[7] The base and change cases are identical except for the zero-cost purchase transaction.[8] The avoided energy cost is the difference between the base case costs and the change case costs.[9]

For avoided capacity costs, DESC also uses the DRR.[10] Using either the resource plan in its latest Integrated Resource Plan ("IRP") or another resource plan, if more appropriate, DESC calculates the incremental capital investment-related revenue required to support its resource plan.[11] For the calculation of avoided capacity costs, DESC derives a change case in its resource plan by considering the impact of adding incremental QF capacity.[12] The avoided capacity cost is the difference between the incremental capacity costs in the base resource plan and the change plan.[13] Although the other parties of record raised concerns with certain inputs and assumptions used in connection with the DRR

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[5] Id.
[6] Id.
[7] Tr. Vol. 2 p. 46.6, lines 15-21.
[8] Id.
[9] Id.
[10] Tr. Vol. 2 p. 46.7, lines 1-7.
[11] Id.
[12] Id.
[13] Id.

methodology, no other party proposed an alternative methodology to calculate DESC's avoided costs or objected to the use of the DRR methodology.

The DRR methodology is used by DESC to calculate both the energy component and capacity component of its avoided costs. The DRR methodology is generally accepted and is used throughout the United States. The Commission finds it is appropriate for DESC to continue using the DRR methodology to calculate its avoided costs.

B. Incremental Change Amount

As part of the DRR methodology, DESC proposes to calculate its avoided energy and capacity costs based upon an assumed incremental addition of 100 MW of QF energy.[14] ORS, however, proposes to calculate the avoided capacity costs based upon an assumed addition of 66 MW of QF energy based upon the capacity of combustion turbine ("CT") units that DESC modeled to use in meeting that capacity change.[15] ORS witness Horii stated the mismatch in generator sizes biases the avoided capacity cost downward.[16] As an alternative, Horii states that the size of the generator could be increased to 100 MW.[17] No other party of record proposed that a different capacity addition should be used in connection with the DRR methodology.

LEI agreed with Horii's position, finding that "the Company is modeling the impact of a 100 MW capacity change, while . . . this need is being met by 66 MW generators."[18] This approach, according to LEI, "underestimates the value of capacity," and thus, "the

[14] Tr. Vol. 2 p. 46.9, lines 7-15.
[15] Tr. Vol. 6 p. 32.22
[16] Tr. Vol. 6 p. 32.21.
[17] Id.
[18] Hearing Exhibit 13 (LEI Report) at p. 31.

size of the capacity change and the size of the generator should be set equal to one another to correct this mismatch."[19]

DESC witness Neely testified that using a capacity change of 100 MW is consistent with DESC's calculation of avoided energy costs and that the MW change should reflect the MW change that it would be required to purchase over the next two years.[20] Neely also noted that PURPA allows using a capacity change of up to 100 MW.[21]

The Commission finds that the mismatch in the avoided capacity cost should be corrected as recommended by ORS witness Horii and supported by LEI. A 66 MW capacity change would be consistent with DESC's modeled new CT generator. Alternatively, Horii noted that a CT plant with hypothetical 100 MW capacity with a hypothetical 100 MW change case could be used to correct the mismatch, but in either scenario, the change case capacity reduction should be the same size as the CT plant.[22] We agree.

1. Avoided Energy Costs – Time Periods

Using the DRR methodology, DESC proposes to calculate its avoided energy costs over two time periods.[23] DESC witness Neely testified that the short-run avoided energy costs that are reflected in Rate PR-1 and which apply to small QFs of not more than 100 kW are calculated for the 12-month period May 2021 through April 2022.[24] For solar QFs that have production capacity up to 2 MW and that are subject to Rate PR-Standard Offer, and for solar QFs that have production capacity greater than 2 MW and that will sell the

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[19] Id.
[20] Tr. Vol. 2 p. 50.3.
[21] Id.
[22] Tr. Vol. 6 p. 32.22.
[23] Tr. Vol. 2 p. 46.7.
[24] Tr. Vol. 2 p. 46.15.

energy generated pursuant to an executed PPA, DESC calculates the long-run avoided energy costs for a 10-year period.[25] DESC then divides these 10-year periods into two groups of five years.[26]

CCL/SACE witness Sercy contended DESC did not justify its use of the time periods for Rate PR-1 and Rate PR-Standard Offer.[27] He stated that the information produced by DESC, such as a "heat map," did not support the time-of-production periods determined by the Company.[28] However, DESC witness Bell explained that the heat map was not used to define hours and, instead, was a Microsoft Excel feature that illustrates differences in data on a spreadsheet and, further, that the formatting provided by Excel is just a starting point and that the average costs of different groups were derived mathematically.[29] Bell explained that the heat maps provided a starting point for the development of groups that were adjusted in a logical manner for season and hour of day to create a practical and useable rate schedule.[30] Sercy responded that the information reflected in the heat map did not support the conclusions drawn by DESC.[31] Bell testified that DESC ran the model to determine pricing periods five times to obtain a more reliable number for the time-of-production periods and that the heat map was not used as a tool to evaluate every run or even the average of those runs, but was just a representation of an evaluation of monthly averages in one of those runs.[32] He further explained that the heat

[25] Tr. Vol. 2 pp. 46.7-46.8.
[26] Id.
[27] Tr. Vol. 4 p. 60.10.
[28] Tr. Vol. 4 pp. 60.11-60.12.
[29] Tr. Vol. 2 pp. 181.17-181.18, 227.
[30] Tr. Vol. 2 p. 181.18.
[31] Tr. Vol. 4 pp. 62.4-62.10.
[32] Tr. Vol. 2 pp. 227-228.

map is immaterial to the calculation and just shows the relative magnitude of the numbers in the selected cells.[33] According to Bell, the colors used on the heat map do not matter; only the numbers, which reflect system costs, matter for the avoided cost calculations.[34]

ORS witness Horii testified DESC's time-of-production periods are reasonable. Specifically, he stated four time-of-production periods are reasonable for Rate PR-1, because the DESC marginal energy costs show only moderate variation by hour of the day within the summer and winter seasons.[35] LEI agreed DESC's approach to establishing pricing periods for Standard Offer rates was "data-driven;" the "production periods selected by DESC are a fair fit for the hourly average price outputs;" and "DESC's pricing periods for Standard Offer rates are sufficient for purposes of this proceeding."[36]

Accordingly, the Commission finds the short-run and long-run time periods used by DESC are reasonable, based on the testimony of ORS witness Horii and the conclusions found in the LEI Report.[37] .

C. Avoided Energy Costs - Natural Gas Pricing Forecasts

DESC witness Neely stated that, because the natural gas forecast is one of the more important inputs into calculating avoided costs, DESC selected NYMEX gas prices for its forecast.[38] CCL/SACE witness Sercy argued that the Company should have used the U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") gas price

[33] Tr. Vol. 2 pp. 229-230.
[34] Tr. Vol. 3 p. 6, lines 16-23.
[35] Tr. Vol. 6 p. 32.12.
[36] Hearing Exhibit 13 (LEI Report) p. 46.
[37] Hearing Exhibit 13 (LEI Report).
[38] Tr. Vol. 2 p. 50.4; p. 52.

projections as required by Commission Order No. 2020-832, which was issued with respect to DESC's IRP, in order to maintain consistency.[39]

Witness Neely asserted that witness Sercy's recommendation would not lead to more accurate gas price projections, because the EIA's use of three gas forecasts does not provide a single forecast and, instead, provides a broad and wide range of how prices might develop depending on numerous factors.[40] Neely stated that using the EIA's AEO forecast in this proceeding is not appropriate or required because a prudent and reliable avoided costs calculation requires a more accurate forecast than that provided by any of the three EIA calculates once a year.[41] Neely further explained his belief that DESC's gas price forecast compares very favorably with the AEO forecast and better represents the expected gas prices at the time of the avoided cost calculation, because it is created based on current factors; whereas, the EIA AEO projections are determined once a year, and market conditions may have changed between the time those projections were made and the calculation of DESC's avoided costs.[42] Neely stated the NYMEX gas price forecast used by DESC provides the inputs DESC needs to accurately calculate avoided costs.[43] Witness Neely further testified the IRP requires three long-term 30-year gas price forecasts, whereas the avoided costs calculation needs only one gas price forecast for ten years.[44] He further

[39] Tr. Vol. 4 pp. 60.7-60.8.
[40] Tr. Vol. 2 p. 50.5.
[41] Id. Also Tr. Vol. 2, p. 52.
[42] Tr. Vol. 2 pp. 50.6; pp. 52-53.
[43] Tr. Vol. 2 p. 53.
[44] Tr. Vol. 2. pp. 74-75.

testified that there is a greater need for accuracy in the avoided cost docket due to the nature of the calculations.[45]

Witness Horii testified DESC's changes in fuel price forecasts were consistent with the EIA AEO forecasts.[46] Witness Sercy, however, concluded that a blended forecast, or a combination of the NYMEX forecast for the first three years, and the EIA AEO forecasts for later years, is more reliable for calculating avoided costs because it accounts for persistent supply and demand factors and better balances short-term and long-term issues.[47] Neely disagreed, stating that the blended forecast would be more accurate in the first year—because it uses the same numbers as DESC used for the first year—but would suffer from the same deficiencies in following years.[48] Neely testified that the objective of DESC's avoided energy cost calculations is to "derive the most accurate projection that can be ascertained at the time the costs are calculated."[49] Witness Neely explained that the EIA AEO "does not provide a single forecast" but, rather, "a broad and wide range of how prices might develop."[50] Thus, according to Neely, while a range of values may be appropriate for an IRP proceeding, "use of th[ese] forecasts is not appropriate or required in this proceeding because . . . avoided costs calculation requires a more accurate forecast," than a once-a-year EIA range of values.[51] Witness Neely further explained that, although short-term NYMEX prices have changed since the time that DESC performed its

[45] Tr. Vol. 2. pp. 76-77.
[46] Tr. Vol. 6 pp. 32.17-32.19.
[47] Tr. Vol. 4 pp. 62.2-62.3.
[48] Tr. Vol. 2 p. 50.7.
[49] Tr. Vol. 2 p. 50.5.
[50] Id.
[51] Id.

calculations, there are fewer changes in future years and the NYMEX provides the most accurate projection of gas prices.[52]

LEI analyzed DESC's approach to establishing its natural gas price outlook and agreed, in part, with DESC and, in part, with witness Sercy. Specifically, LEI found that for the first three years, DESC's use of natural gas futures "represent[s] the best estimate for costs."[53] However, "[b]eyond three years," LEI agreed with Sercy that the EIA AEO's reference case outlook is preferable for establishing a longer-term gas price outlook.[54] Each approach, according to LEI, is "equally defensible," but LEI, nevertheless, found "the approach taken by DESC . . . is in line with approaches taken by LEI in the past to establish longer-term gas price outlooks."[55] Thus, LEI concluded that "the price outlook used by DESC" is "within a reasonable range of potential outcomes."[56]

We agree with LEI's findings that, for the first three years, DESC's use of natural gas futures "represent[s] the best estimate for costs." We further agree with LEI and Searcy that the EIA AEO's reference case outlook is preferable for establishing a longer-term gas price outlook. We believe that this blended methodology will provide more accurate natural gas price forecasting for short-term and long-term prices than either method used alone. Accordingly, we adopt this blended approach for natural gas price forecasting of avoided energy costs, as described by LEI.

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[52] Tr. Vol. 2 pp. 61-62.
[53] Hearing Exhibit 13 (LEI Report) p. 43.
[54] Id.
[55] Id.
[56] Id.

D. Avoided Energy Costs – Standard Offer Non-Solar Pricing Periods

For non-solar QFs subject to Rate PR-Standard Offer, DESC witness Neely testifies that DESC follows the same methodology used for solar QFs, but then DESC allocates the avoided energy costs into 11 time-of-production periods reflecting the amounts non-solar QFs would be paid based on how much energy they produce in each of the 11 time-of-production periods.[57]

CCL/SACE witness Sercy contended that DESC had not justified its use of the time periods for Rate PR-1 and Rate PR-Standard Offer.[58] He stated that the information produced by DESC, such as a "heat map," did not support the time-of-production periods determined by the Company.[59] However, DESC witness Bell explained that the heat map was not used to define hours and, instead was a Microsoft Excel feature that illustrated differences in data on a spreadsheet and, further, that the formatting provided by Excel is just a starting point and that the average costs of different groups were derived mathematically.[60] Bell testified the heat maps provided a starting point for the development of groups that were adjusted in a logical manner for season and hour of day to create a practical and useable rate schedule.[61]

Witness Sercy responded the information reflected in the heat map did not support the conclusions drawn by DESC.[62] Witness Bell testified DESC ran the model to determine

[57] Tr. Vol. 2 p. 46.8.
[58] Tr. Vol. 4 p. 60.10.
[59] Tr. Vol. 4 pp. 60.11-60.12.
[60] Tr. Vol. 2 pp. 181.17-181.18, p. 227.
[61] Tr. Vol. 2 p. 181.18.
[62] Tr. Vol. 4 p. 62.

pricing periods five times to obtain a more reliable number for the time-of-production periods and that the heat map was not used as a tool to evaluate every run or even the average of those runs but was just a representation of an evaluation monthly averages in one of those runs.[63] Bell further explained the heat map is immaterial to the calculation and just shows the relative magnitude of the numbers in the selected cells.[64] He testified the colors used on the heat map do not matter; only the numbers, which reflect system costs, matter for the avoided cost calculations.[65]

ORS witness Horii testified DESC's time-of-production periods are reasonable. Specifically, he stated four time-of-production periods are reasonable for Rate PR-1 because the DESC marginal energy costs show only moderate variation by hour of the day within the summer and winter seasons.[66] Horii further opined the 11 time-of-production periods for Rate PR-Standard Offer are reasonable because the higher granularity for the 11 periods will help incentivize generators to export energy in hours of highest value to DESC.[67]

LEI agreed DESC's approach to establishing pricing periods for Standard Offer rates was "data-driven," the "production periods selected by DESC are a fair fit for the hourly average price outputs," and "DESC's pricing periods for Standard Offer rates are sufficient for purposes of this proceeding."[68]

[63] Tr. Vol. 2 pp. 227-228.
[64] Tr. Vol. 2 pp. 229-230.
[65] Tr. Vol. 3 p. 6, lines 16-24.
[66] Tr. Vol. 6 p. 32.12.
[67] Tr. Vol. 6 p. 32.16.
[68] Hearing Exhibit 13 (LEI Report) p. 46.

The Commission agrees with the testimony of witnesses Bell and Horii, and the LEI Report on this matter, and finds the use of the described 11 time-of-production periods to be reasonable. These periods are approved. We agree with LEI that DESC's approach on this issue was data-driven, and that the production periods selected by DESC are a fair fit for the hourly average price outputs. Consequently, we hold that DESC's pricing periods for Standard Offer rates are sufficient for purposes of this proceeding, and we adopt them as such.

E. Avoided Energy Costs – A Single Technology-Neutral Energy Rate Schedule

DESC proposed different energy rates and rate structures for solar QFs and non-solar QFs.[69] CCL/SACE witness Sercy asserted that solar producers should be allowed to use DESC's non-solar rates, contending those are, in effect, technology neutral rates.[70] He testified this would compensate each stand-alone solar QF more appropriately, based on its unique production profile that may vary based on geographic location and choices of technology.[71] Regarding allocation of capacity value due to seasonal peaks, Sercy notes that "DESC has experienced more summer peaks in the last decade than winter peaks, assigning all capacity value to winter hours is questionable."[72]

LEI recommended the "use of a single avoided capacity rate" on grounds that "a resource's capability to deliver capacity when required should determine its payment regardless of technology type."[73] DCA shares this view. LEI found that "technology

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[69] Tr. Vol. 2 p. 80.
[70] Tr. Vol. 4 pp. 60.12-60.13.
[71] Tr. Vol. 4 pp. 60.13-60.14.
[72] Tr. Vol. 4 p. 60.28.
[73] Hearing Exhibit 13 (LEI Report) p. 36.

neutrality avoids having different avoided costs for the same hour, provides clear price signals, and assures values are assigned appropriately when considering costs avoided from a utility's perspective...."[74]

The Commission approves the use of a technology-neutral approach for all resources. The Commission further approves the use of a single-technology-neutral rate schedule (i.e., DESC's proposed non-solar QF energy rates) to be used in place of separate rates specific to stand-alone solar QFs. As concluded by LEI, we find it is reasonable to rely on the resource's capability to deliver capacity when required, regardless of technology type.

F. Avoided Energy Costs – PR-1 Non-Solar Pricing Periods

ORS witness Horii recommended a modification to the four Time of Use ("TOU") periods for non-solar generators on the PR-1 Rate to provide a more focused period to "provide even greater incentives for generators to provide power when it is most valuable to DESC and its retail customers."[75] Horii testified that DESC's proposal has an 11:00 am to 11:00 pm peak period, but a review of DESC's 2022 hourly energy marginal costs shows that the average summer marginal costs between 11:00 a.m. and 2:00 p.m. are significantly lower than the average costs for the other peak hours.[76] As a result, ORS recommends shifting the summer hours of 11:00 a.m. to 2:00 p.m. from the summer peak period to the summer off-peak period, 2:00 p.m. to 11:00 p.m.[77] According to Horii, this shift "increases

[74] Id.
[75] Tr. Vol. 6 p. 32.13.
[76] Id.
[77] Id.

the average summer peak marginal cost and increases the accuracy of the TOU averages by 3% over the entire year."[78]

DCA supports the adoption of ORS's recommendation on summer on-peak periods and points out that evidence provided in the current proceeding demonstrates that DESC's avoided cost of energy are driven by high marginal costs in early morning winter hours and late evening summer hours.[79] Horii testified time-variant energy credits provide price signals to generators to provide electricity when most valuable. He further stated a more focused on-peak period provides even greater incentives for generators to provide power when it is most valuable to DESC and its retail customers.[80] DCA believes that this is particularly important when considering non-dispatchable, intermittent resources, such as solar QFs, which generate electricity at higher levels during early afternoon hours coincident with high solar angles. Compensating these solar QFs for generation during these hours at the same on-peak rates as generation during the early evening hours during peak marginal costs leads to these customers being overcompensated for their generation sold to DESC. DCA asserts that "[t]his is counter to the statutory intents of PURPA and Act 62 that utility ratepayers do not subsidize QFs. (*see* Application at ¶31, referencing Joint Conference Comm. Report, H.R. Conf. Rep. No. 95-1750 at 98; and S.C. Code Ann. § 58-41-20(A))."[81]

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[78] Id.
[79] Tr. Vol. 6 p. 32.13.
[80] Id.
[81] Post-Hearing Brief of the South Carolina Department of Consumer Affairs p. 13.

DESC's witness Bell explained that although DESC believes its determinations with respect to the four time-of-production periods for Rate PR-1 non-solar are reasonable, it does not oppose witness Horii's recommendation.[82]

We agree with the reasoning presented by ORS and DCA. We further note DESC did not oppose this reasoning. We therefore find ORS's proposed restriction on summer on-peak hours, eliminating the period 11:00 a.m. to 2:00 p.m. from on-peak, is just and reasonable.

G. Avoided Capacity Costs

Neely testified capacity costs are the costs associated with providing the capability to deliver energy and consist primarily of the capital costs of facilities.[83] As with avoided energy, DESC used the DRR methodology to calculate its avoided capacity costs.[84] In calculating avoided capacity costs for the base case, the Company calculates the incremental capital investment related revenue required to support its resource plan, either the Integrated Resource Plan or another resource plan if more appropriate.[85] As established by DESC witness Neely, for the change case, the Company analyzes the estimated impact that a purchase from a 100 MW facility would have on the resource plan.[86] The avoided capacity cost is the difference between the incremental capacity costs in the base case and the change case.[87]

[82] Tr. Vol. 2 p. 181.20,
[83] Tr. Vol 2 p. 46.5.
[84] Id.
[85] Tr. Vol 2 p. 46.7.
[86] Id.
[87] Id.

DESC proposes calculating the avoided capacity cost for solar QFs subject to the Standard Offer Rate and Rate PR-1 using a 5% Effective Load Carrying Capacity ("ELCC") rate.[88] The proposed 5% ELCC rate differs from the 11.8% ELCC described in Order No. 2020-244 in DESC's last avoided cost proceeding because the 11.8% rate was calculated assuming only 500 MW of existing solar generation on the system.[89] Neely testified the updated calculation includes all 973 MW of existing solar power PPA that had been signed at the time of the calculation.[90] Furthermore, he stated the ELCC rate of incremental solar generation decreases as more solar is added to the system as expected for additional and similar resources.[91]

In rebuttal, DESC disagreed with the recommendation ORS made that 66 MW should be used as the assumed capacity change in the calculation of avoided capacity.[92] DESC witness Neely argued:

> Using a capacity change of 100 MW is consistent with the Company's calculation of avoided energy costs. Moreover, the MW change should be reflective of the MW that the Company could expect that it would be required to purchase from QFs over the next two years, and it is reasonable to expect that several hundred MW of QFs will be built in the Company's service territory over the next two years. Finally, PURPA specifically provides that a utility may use a capacity change of up to 100 MW to calculate avoided costs.[93]

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[88] Tr. Vol 2 p. 46.10.
[89] Id.
[90] Id.
[91] Id.
[92] Tr. Vol. 2 p. 50.3.
[93] Id.

DESC agreed with ORS's recommendation the year 2022 should be used as the base year for the avoided capacity calculation and accepted that proposal.[94] According to DESC witness Neely, accepting this change would increase the avoided capacity cost for non-solar QFs that qualify for the Standard Offer and Rate PR-1, under DESC's calculations, to $58.81 per kW-year.[95] Furthermore, DESC contends for solar QFs that qualify for the Standard Offer and Rate PR-l, the avoided capacity cost increased to $2.9405 per kW-year.[96] DESC disagreed with the recommendations made by intervenor witnesses regarding avoided capacity costs.

CCL/SACE witness Sercy raised several concerns regarding DESC's proposed avoided capacity rates. He argued QFs "should be compensated in such a way that allows for a level of unavailability that is reasonably comparable to the level of unavailability of utility-owned resources," and asserted that a "performance adjustment factor" ("PAF") within the avoided capacity rate calculations would accomplish this.[97] Sercy further noted DESC's proposed tariff for non-solar QFs requires them to be available and dispatchable in all capacity payment hours to receive any capacity payment, but contends that "QFs should be paid based on their availability during the capacity payment hours, and if they are available for part of those hours, they should be paid proportionally."[98]

Sercy disagreed with the capital cost assumptions DESC utilized for aeroderivative combustion turbine technology ("aero-CT technology") and recommended the EIA report

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[94] Id
[95] Id.
[96] Id
[97] Tr. Vol. 4 pp. 60.18-19.
[98] Tr. Vol. 4 pp. 60.19-20.

on Capital Cost and Performance Characteristics be used.[99] Regarding DESC's solar specific avoided capacity calculation, Sercy expressed concerns about DESC's application of the ELCC methodology, although he "broadly" agreed an ELCC approach is reasonable and viewed "such an approach as an improvement on DESC's previous approach to solar accreditation."[100] Sercy ultimately concluded that "DESC's 2021 ELCC analysis cannot be fully evaluated due to use of opaque SAS code, but based on the elements that can be assessed, it does not clear the bar of further advancing the rigor and accuracy of this important component of avoided cost calculations."[101] Sercy recommended a technology neutral capacity rate for which solar generation would be eligible and under which not all capacity value would be allocated to a three-hour period during the winter season.[102] He recommended a winter allocation of 52% and a summer allocation of 48% and identifying particular hours during the winter and summer months where much of the top 1% net loads occur.[103]

ORS witness Horii testified the DRR methodology used by DESC is one of the generally accepted methods for calculating PURPA avoided costs and is used throughout the United States.[104] It is the same methodology DESC used and that was approved by the Commission in DESC's last avoided cost proceeding.[105] While Horii generally agrees with DESC's methodology and assumptions, he recommends two corrections to prevent

[99] Tr. Vol. 4 p. 60.20.
[100] Tr. Vol. 4 pp. 60.22-23.
[101] Tr. Vol. 4 p. 60.27.
[102] Tr. Vol. 4 pp. 60.27-28.
[103] Tr. Vol. 4 pp. 60.29-30.
[104] Tr. Vol. 6 p. 32.21.
[105] Id.

underestimation of the value of generation capacity.[106] Horii first suggests using 66 MW as the assumed capacity change in the change case, so that the assumed capacity change is the same as the assumed size of a new generating unit used by DESC in the analysis.[107] Horii also testified the DESC model assumes a 100 MW capacity change in their change case, yet, models meeting that 100 MW change with 66 MW generators.[108] He contends the mismatch in generator size biases the avoided capacity cost downward.[109] Furthermore, he states eliminating the mismatch by using 66 MW for the capacity change and the generator sizes increases avoided capacity cost by 17%.[110]

In DESC's previous avoided cost proceeding, the Commission accepted ORS's recommendation to ensure the generation change is consistent with the new generator size.[111] In that proceeding, DESC used a 100 MW generation change in the change case and used a 93 MW new generator size.[112] The Commission adopted ORS's recommendation to set the change case capacity change at the same size as the modeled new generation (Order No. 2019- 847, pp. 24-25).[113] ORS recommends in this docket to use a 66 MW capacity change to be consistent with DESC's modeled new CT generator.[114]

Witness Horii's second recommended correction is that DESC should use 2022 as the reference year for the avoided cost calculations.[115] He testified DESC's proposed

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[106] Id.
[107] Id.
[108] Id.
[109] Id
[110] Id.
[111] Tr. Vol. 6 p. 32.22.
[112] Id.
[113] Id.
[114] Id.
[115] Tr. Vol. 6 p. 32.21.

calculations rely upon 2020 as the reference year, which results in an 18% underestimation of the avoided capacity cost.[116]

As stated by ORS witness Horii, the DRR method calculates the avoided cost of capacity based on the difference in the present values of the capacity-related revenue requirement of the base case minus the change case.[117] The present value calculations are used to convert future cash flows to an equivalent value in a reference year.[118] DESC used a reference year of 2020 for the DRR calculations.[119] However, a more appropriate year, according to Horii, is 2022 because this docket is determining avoided capacity values for 2022.[120] The witness states that the choice of the reference year is impactful because use of a reference year other than 2022 will arbitrarily decrease or increase the DRR avoided capacity cost result.[121] Horii asserts, for example, using a reference year of 2010 would reduce the avoided capacity cost by almost 63% relative to a 2022 reference year, while using a reference year of 2030 would increase the avoided capacity cost by over 93%.[122] Since this docket is setting avoided capacity costs for use in 2022 tariffs, ORS recommends that 2022 be used for the reference year of the present value calculations, and thereby match the avoided capacity costs with when the associated tariffs will be effective.[123]

DESC agreed with ORS's recommendation that the year 2022 should be used as the reference year for the avoided capacity calculation and accepted that proposal, and DESC

[116] Tr. Vol. 6 pp. 32.21-22.
[117] Tr. Vol. 6 p. 32.23.
[118] Id.
[119] Id.
[120] Id.
[121] Id.
[122] Id.
[123] Id.

witness Rooks attached tariffs to his rebuttal reflecting this change.[124] DESC disagreed with ORS's recommendation to use 66 MW as the assumed capacity change in the change case and recommended a 100 MW change is appropriate.

In response to DESC's argument that a 100 MW change is consistent with the calculation of avoided energy costs, witness Horii testified: (1) avoided energy and capacity costs are based on completely independent models and one model looks at short term operating costs and the other model looks at long-run capital costs for plant additions; (2) the avoided energy costs for solar do not use a 100 MW change for all hours, but instead use a solar profile with MW impacts that vary hourly; and (3) he is unaware of any PURPA requirement that the same MW change be used for each model.[125]

In response to DESC's argument that the MW change should be reflective of the number of QFs expected over the next two years, Horii testified that while 100 MW is closer to the several hundred MWs of QFs projected over the next two years, 100 MW is so far away from several hundred MWs that it would be a stretch to deem it reflective of what is expected over the next two years and not a justification for departing from the ruling in Order No. 2019-847.[126] In response to DESC's assertion that PURPA provides that a utility can use up to 100 MW to calculate avoided costs, Horii testified PURPA allows an increment up to 100 MWs but does not mandate that only 100 MWs can or should be used, and that 66 MWs equally complies with the PURPA specification.[127]

[124] Tr. Vol. 2 p. 50.3.
[125] Tr. Vol. 6 pp. 34.5-6.
[126] Tr. Vol. 6 p. 34.6
[127] Id.

There are two corrections recommended by witness Horii to increase avoided capacity rates by 37.5%.[128] Horii testified the solar QF $/kWh credit is lower than the non-solar QF $/kWh credit for two reasons.[129] First, he asserts the non-solar QFs are only credited for output from 6:00 am to 9:00 am in three winter months whereas the solar QFs receive a capacity credit for all of their output, regardless of the time of day or the season.[130] Secondly, Horii contends the credit provided to solar QFs is reduced for the fact that the generation capacity reduction per nameplate kW of solar generation is decreasing with higher levels of solar penetration on the DESC system.[131] DESC estimates that the ELCC-based value is now only 5% of nameplate capacity.[132] Horii agrees with the use of ELCC analyses to determine capacity contributions from intermittent resources.[133]

DCA asserts the Company's proposed avoided cost of capacity represents a fair valuation of the economic value of avoided electric capacity additions on the Company's system. DCA further contends the proposed adjustments of ORS and CCL/SACE do not reflect that the economic value of capacity and the adjustments are typically less than the full replacement cost of capacity. DCA states that, if adopted, such adjustments could lead to overcompensation and subsidization. For these reasons, DCA believes that the Commission should approve DESC's requested avoided cost of capacity based on $58.81 per kW-year.[134]

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[128] Tr. Vol. 6 p. 32.24
[129] Id.
[130] Id.
[131] Id.
[132] Tr. Vol. 6 p. 32.25.
[133] Id.
[134] Post-Hearing Brief of the South Carolina Department of Consumer Affairs p. 10.

LEI agreed with ORS's recommendation to use 66 MW as the assumed capacity change in the change case and that the size of the capacity change and the size of the generator should be equal to one another to correct the mismatch in DESC's approach.[135] LEI agreed with CCL/SACE witness Sercy that EIA's cost assumptions for an aero-CT addition should be used for avoided capacity cost calculations. LEI states: "as the EIA's cost assumptions for an aero-CT addition are the closest to the 100 MW being assessed, they serve as the best source for avoided capacity calculations."[136]

The Commission agrees with LEI, ORS, and CCL/SACE witnesses that: (1) DESC should match the capacity change being assessed and the generating unit size; and (2) that capital and fixed operating and maintenance costs may need to be adjusted upwards. DESC shall provide updated rates that recognize these principles.

H. Performance Adjustment Factor

LEI also recommends that a Performance Adjustment Factor ("PAF") of 1.05 should be included in calculating avoided capacity costs.[137] LEI explains the 1.05 PAF is based on the PAF included in Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's ("DEC/DEP") 2019 avoided cost proceeding.[138] CCL/SACE witness Sercy also recommended a 1.05 performance adjustment factor that would increase total avoided capacity costs.[139] According to witness Sercy, a PAF is meant "to allow for a reasonable level of generator unavailability while still providing full compensation for cost recovery

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[135] Hearing Exhibit 13 (LEI Report) p. 31.
[136] Id.
[137] Hearing Exhibit 13 (LEI Report) pp. 31-35.
[138] Id.
[139] Tr. Vol. 4 p. 60.21.

purposes."[140] Sercy testified that a PAF is necessary "in order to treat QFs on a fair and equal footing with utility-owned resources."[141] DESC does not propose application of a PAF and asserts that it is at odds with the FERC's position guaranteeing QFs' cost recovery is fundamentally inconsistent with PURPA. DESC states that a PAF would provide full compensation for cost recovery purposes to QFs, rather than avoided costs only. DESC witness Neely asserted that "[a] PAF artificially inflates capacity values,"[142] because to compensate QFs for periods of unavailability would result in "DESC's customers [paying] for something they did not receive. This would be in direct conflict with the requirements of Act No. 62," which requires rates to accurately reflect a utility's avoided cost.[143] LEI agreed with witness Sercy that "a PAF [should] be included in calculating avoided capacity cost" to "QFs on a more equal footing with utility-owned resources."[144] LEI reasoned that the "PAF should not be viewed as an artificial inflation, but an adjustment that leads to a more accurate depiction of the costs for capacity under an understanding that outages consistent with a generic CT is expected."[145] Thus, LEI concurred with Sercy's recommendation of a 1.05 PAF.

DCA opposes the adoption of the proposed PAF in this Docket. DCA points out that CCL/SACE suggest that the Commission approve a PAF of 1.05 based on DEC/DEP's 2019 avoided cost rate proposal.[146] According to DCA, the Commission should reject any

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[140] Tr. Vol. 4 p. 60.19.
[141] Tr. Vol. 4 p. 60.18.
[142] Tr. Vol. 2 p. 50.16.
[143] Tr. Vol. 2 p. 50.15, lines 3-4, p. 94.
[144] Hearing Exhibit 13 (LEI Report) p. 35.
[145] Id.
[146] Tr. Vol. 4 p. 60.19.

proposed adjustment to DESC's avoided capacity cost estimates for generator unavailability that is not grounded on an examination of DESC's generators. DCA asserts the DEC/DEP and DESC utility systems have different resources supporting them. Further, DCA argues that arbitrarily assigning an upward adjustment to the avoided capacity cost calculations of DESC could result in an inappropriately high compensation rate for QFs for capacity provided to the DESC system. DCA further contends this would result in DESC ratepayers inappropriately subsidizing QFs for this capacity, in direct contradiction to S.C. Code Ann. § 58-41-05 and PURPA. The Commission, according to DCA, should defer applying any PAF until it has DESC-specific information to judge the acceptability of any proposed factor.[147]

With regard to the 1.05 PAF, the Commission acknowledges that it found a PAF proposed by Duke Energy Carolinas and Duke Energy Progress in Docket Nos. 2019-185-E and 2019-186-E to be "reasonable and supports Act 62's objective of placing QF generators and utility generators on equal footing in terms of reasonable allowance for unplanned outages."[148] Turning to this proceeding, witness Sercy argued in favor of a PAF because it will "allow for a reasonable level of generator unavailability while still providing full compensation for cost recovery purposes, which . . . is how utility-owned generators are treated."[149] However, subsequent to the Commission's order in Docket Nos. 2019-185-E and 2019-186-E, the FERC in Order No. 872 (Sep. 2, 2020) further clarified the contours and limits of PURPA. Pertinent here, FERC stated that "[g]uaranteeing QFs cost recovery

[147] Post-Hearing Brief of the South Carolina Department of Consumer Affairs p. 11.
[148] Order No. 2019-881(A) (Jan. 2, 2020) p. 30.
[149] Tr Vol. 4 p. 60.19.

is fundamentally inconsistent with PURPA, which sets the rate the QF is paid at the purchasing electric utility's avoided cost, not at the QF's cost."[150]

We decline to adopt the proposed PAF of 1.05 proposed by CCL/SACE witness Sercy. We do, however, agree with Sercy and LEI that using data in the EIA's AEO for capital cost assumptions is reasonable. Finally, we adopt the use of a single avoided capacity rate.

I. Avoided Capacity Costs - Technology Neutrality

On the issue of technology neutrality, LEI recommends the use of a single avoided capacity rate.[151] On the issue of seasonal allocation, LEI indicates winter reserve margin requirements are driving differentiation in the avoided cost change case as noted by DESC.[152] Nevertheless, LEI indicated it is possible DESC's capacity allocation window may be overly narrow seasonally and recommended that going forward DESC assess the value of summer capacity and provide more clarity and data substantiation on why it believes summer capacity has little to no value should it reach that conclusion. The Commission finds the use of a single avoided capacity rate, as a resource's capability to deliver capacity when required should determine its payment regardless of technology type.[153]

J. Avoided Capacity – Single Rate

As stated herein and above, the Commission also adopts the use of a single avoided capacity rate, as a resource's capability to deliver capacity when required should determine

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[150] 85 FR 54638-01, 54646.
[151] Hearing Exhibit 13 (LEI Report) p. 36.
[152] Id.
[153] Id. p. 37.

its payment regardless of technology type. Due to the adoption of the single avoided capacity rate, the Commission adopts the LEI position that the ELCC issue is not relevant in this proceeding, because resources only receive the rate if they generate in the specific periods.[154] The Commission finds that ELCC is therefore moot.

K. Avoided Capacity – Reference Year

DESC agrees with Horii's recommendation to use 2022 as the reference year, and DESC incorporated the same into its proposed rates. The Commission also agrees with witness Horii's recommended correction to use 66 MW as the assumed capacity change used in the change case so that it is the same as the assumed size of a new generating unit used by DESC in the analysis. LEI agreed with this recommendation as well. The Commission finds witness Horii's analysis of this issue persuasive and adopts the use of 2022 as the reference year.

L. Avoided Capacity - Seasonal Allocation

DESC allocates capacity payments for non-solar to a 3-hour winter period (6 a.m.-9 a.m., December through February). CCL/SACE witness Sercy recommends a 52% winter/48% summer allocation, with pricing periods of 6 a.m. – 9 a.m. (winter) and 2 p.m. – 8 p.m. (summer).[155]

Both DCA and ORS recommend that the Commission reject the proposed seasonal allocation by CCL/SACE. DCA asserts that their proposed seasonal allocation would create negative impacts for DESC ratepayers. DCA contends the proposed seasonal

[154] Id. p. 36.
[155] Tr. Vol. 4 pp. 60.28-30.

allocation would lead to overcompensation for QFs that produce and sell electricity during afternoon summer hours; but there would be negligible operations during early winter morning hours prior to or shortly after sunrise (i.e., winter peak). ORS recommends rejection of the proposed seasonal allocation and asserts that solar generators should be eligible for the non-solar avoided capacity rates.

The Commission declines to approve the seasonal allocation changes proposed by CCL/SACE and the recommendation that solar generators be eligible for the non-solar avoided capacity rates, since neither DCA nor ORS provided convincing evidence on this issue. LEI did not recommend changing the seasonal allocation proposed by DESC.[156] Accordingly, the Commission adopts DESC's proposed seasonal allocation at this time. However, the Commission directs and orders DESC, going forward, as recommended by LEI, to assess the value of summer capacity and winter capacity. DESC must also provide more clarity and data substantiation regarding the value of summer and winter capacity.[157]

M. Variable Integration Charge

The LEI Report indicates the variable integration cost ("VIC") is the cost incurred by the Company to integrate intermittent solar generation into the system. The report also explains, as more intermittent solar is added to the DESC system, the amount of unpredictable generation increases, requiring additional operating reserve and ramping capability.[158] LEI states the increased costs associated with carrying more operating reserve to meet unexpected changes in intermittent solar generation,[159] as well as other associated

[156] Hearing Exhibit 13 (LEI Report) p. 36-37.
[157] Id.
[158] Tr. Vol. 6 p. 32.7.
[159] Tr. Vol. 3 p. 59.6

costs,[160] represent the integration costs to the Company. DESC witness David testified that at present there are 973 megawatts of solar generation projects on the DESC system.[161] According to the Guidehouse Variable Integration Cost Study, 633 megawatts have power purchase agreements with DESC containing a VIC charge clause, whereas 340 megawatts do not include such a clause in their respective contracts.[162] With respect to future solar QFs that seek to provide DESC with energy under Rate PR-1, Rate PR-Standard Offer, or Rate PR-Form PPA, DESC employed Guidehouse, Inc. to complete an independent study to determine appropriate VIC rates (the "Guidehouse Study").[163] The study used operational data provided by DESC to Guidehouse.[164]

The Guidehouse Study examined the cost to integrate intermittent solar generation under a baseline scenario and three different scenarios of solar integration into the DESC system.[165] DESC witness David testified the "baseline scenario includes all of the interconnected solar generation with PPAs that do not include any [VIC] clauses, totaling 340 megawatts," and that the "Tranche 1" scenario includes all baseline solar generation plus 632 megawatts of PPAs with QFs that contain a VIC clause. [166] He further noted the "Tranche 2" scenario accounts for 100 megawatts of additional solar penetration on top of the Tranche 1 and baseline scenarios.[167] David also reported the "Tranche 3" scenario

[160] Tr. Vol. 6 p. 32.7.
[161] Hearing Exhibit 3 p. 6.
[162] Tr. Vol. 3 p. 55.
[163] Tr. Vol. 3 p. 59.4, Hearing Exhibit 3.
[164] Tr. Vol. 2 p. 174.23.
[165] Tr. Vol. 3 pp. 54-55, p. 59.4.
[166] Tr. Vol 3. p. 55.
[167] Id.

accounts for 300 more megawatts of solar penetration in addition to Tranche 2, Tranche 1, and the baseline scenario.[168]

Witness David testified "[a]s solar penetration increases, the levelized cost of maintaining additional operating reserves will increase . . . due to having to operating the system in an increasingly less efficient manner."[169] Illustrating the point, DESC witness Kassis further elaborated on reduced operational efficiency, testifying that "[s]ometimes, as a result of the QF power, DESC must shut down low-cost flexible generation, which creates higher operating costs."[170] The Guidehouse Study "forecast[ed] the amount of load-following reserves needed with increasing renewable penetration based on the National Renewable Energy Laboratory's (NREL) Solar Integration Data Sets."[171] Forecast error under this approach was "simulated based on historical operation of the assumed resources including the impacts of regional weather and geographic diversity."[172] The Study then calculated the incremental megawatt reserves required by month across all solar Tranches. The Guidehouse Study employed PROMOD, a production cost modeling tool, to analyze system impacts and calculate total production costs with and without the additional reserves required to account for increased solar penetration.[173] "The difference of the system costs of the two PROMOD runs were then compared to calculate the cost of integrating solar."[174] The Guidehouse Study concluded that the "levelized VIC over the

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[168] Id.
[169] Tr. Vol 3. p. 57.
[170] Tr. Vol 1. pp. 20.17-18.
[171] Hearing Exhibit 3 p. 6.
[172] Id.
[173] Hearing Exhibit 3 p. 7.
[174] Hearing Exhibit 3 at p. 25.

forecast period between 2022 to 2031" was $1.8016 MWh for Tranche 1 (341 to 973 megawatts), $3.4301 MWh for Tranche 2 (974 to 1073 megawatts), and $4.6345 MWh for Tranche 3 (1074 to 1373 megawatts).[175]ORS witness Horii agreed with witness David that the integration of renewable generation creates additional costs for utilities.[176] Horii testified that his firm, Energy and Environmental Economics, Inc. ("E3"), in its work in California and Hawaii found "that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation."[177] Further, Horii found "the overall concepts of the calculation methodology used in the Guidehouse Variable Integration Study to be reasonable."[178]

Nevertheless, witness Horii advised this Commission not to adopt the VIC charges proposed by the Company asserting that "Guidehouse ha[d] not justified their forecast of incremental operating reserve needed to accommodate forecast uncertainty."[179] Specifically, Horii stated that the Guidehouse Study "models solar output based on the differences between 4-hour ahead schedules and actual solar output" and noting that the study itself recognized that "ideally 1-hour ahead schedules" should have been used.[180] He testified that "a 2015 study suggests that solar forecast errors could be reduced by about half if 1-hour ahead schedules are used."[181] Horii also asserts this impacts VIC, because

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[175] Hearing Exhibit 3 p. 8.
[176] Tr. Vol. 6 p. 32.7.
[177] Id.
[178] Tr. Vol. 6 p. 32.8.
[179] Id.
[180] Tr. Vol. 6 at p. 32.9.
[181] Id.

"[a] more accurate 1-hour ahead forecast would reduce unexpected variation of solar generation and thereby reduce the costs of solar integration."[182] Witness Horii, therefore, recommended that VIC remain at $0.96/MWh subject to true-up pending the results of an independent comprehensive study.[183]

LEI found that given the "extent of contrary evidence introduced regarding the VIC analysis," a "truly independent study" is required.[184] Therefore, LEI "concur[ed] with the recommendation proposed by Horii."[185] However, DESC witness Hanzlik disagreed with Horii that employment of a one-hour ahead schedule would substantially reduce "the need for operating reserve," and thus, VIC costs, because DESC must still respond to solar variability "in real time."[186] DESC witness Bell also testified that a one-hour ahead schedule will not meaningfully reduce VIC because "[r]ecent forecasting may increase accuracy in the short term, but does not create additional firm capability that is needed to maintain reserve."[187] Bell further explained that the one-hour forecast does not help because the Company usually does not have a one-hour unit available to provide increased reserves and, thus, the Company has to react before the one-hour forecast is issued.[188]

Notwithstanding the concerns raised in his testimony, witness Horii recommended to this Commission that, if it was the intent of this Commission to adopt a new VIC rate in this Docket (as opposed to commissioning another VIC study at some point in the future),

[182] Tr. Vol. 6 p. 34.5.
[183] Tr. Vol. 6 p. 32.9.
[184] Hearing Exhibit. 13 (LEI Report) p. 54.
[185] Hearing Exhibit. 13 (LEI Report) p. 55.
[186] Tr. Vol. 1 p. 186.
[187] Tr. Vol. 2 p. 177.
[188] Tr. Vol. 2 p. 222.

then he would recommend the Commission adopt the $1.80 MWh proposed by the Company for Tranche 1 solar integration.[189]

CCEBA witness Burgess offered various criticisms of the Guidehouse Study. Burgess introduced an exhibit showing monthly average operating reserves into his testimony which he asserted shows that "the typical amount of operating reserves DESC has historically carried on its system … far exceeds what DESC claims is necessary to integrate solar Tranches 1, 2, and 3."[190] From this, he concluded that "the incremental integration cost to be essentially zero most of the time."[191]

Like witness Horii, Burgess raised concerns about the use of four-hour ahead schedules in the Guidehouse Study as opposed to one-hour ahead schedules. However, as discussed above, witness Hanzlik and witness Bell, both of whom are familiar with the DESC operating system, assert that the use of a one-hour ahead schedule, even if it improves forecast accuracy, will not impact the Company's need for additional operating reserves to deal with increased solar penetration into the system, which drives VIC cost.

LEI reached a similar conclusion to that of Horii, stating that "if the Commission believes that it must set a fixed VIC as part of this proceeding, LEI concurs with Horii that DESC's proposed VIC for Tranche 1 of $1.80/MWh may be a reasonable value." [192] LEI witness Goulding, while under cross-examination, reiterated this position, testifying that LEI "believed and continue[s] to believe that if the Commission is unable to continue with

[189] Tr. Vol. 6 p. 97.
[190] Tr. Vol. 5 p. 16.14.
[191] Tr. Vol. 5 p. 16.15.
[192] Hearing Exhibit 13 (LEI Report) p. 56.

an interim VIC of 96 cents, that the $1.80 falls within the range of reasonable potential outcomes."[193]

The Commission finds it reasonable to set a fixed VIC as part of this proceeding and adopts the recommendation of Horii and LEI that DESC's proposed VIC for all tranches of $1.80/MWh is a reasonable value for all newly contracted resources over the next two years and for existing contracts in Tranche 1 which previously used the interim VIC of $0.96MWh with a true up provision. For all new contracts in Tranche 2 or Tranche 3, DESC shall use a VIC of $1.80MWh. A fixed VIC provides certainty for solar project developers, and the Commission determines that continuing the interim VIC of $0.96/MWh is risking uncertainty for the ratepayer.

N. Mitigation Protocols

As described above, much of the testimony in this proceeding revolved around the value of the VIC, which represents the costs incurred by DESC to integrate QF solar generators onto its system. However, DESC witness Kassis provided testimony regarding a potential path for these QFs to mitigate the costs by complying with DESC's proposed Mitigation Protocols.[194] Kassis explained that any solar QF desiring to reduce or eliminate the VIC must first "reduce or eliminate the need for DESC to carry additional operating reserves as a result of such QF's generation," and to do this QFs must smooth out their intermittent generation profile by reducing unplanned drops in generation.[195] Recognizing this concept, the Mitigation Protocols contain a Solar Site Variability Metric (the

[193] Tr. Vol. 7 p. 79, lines 13-16.
[194] Tr. Vol. 1 p. 20.40.
[195] Id.

"SSVM"), which is calculated pursuant to a spreadsheet provided by DESC.[196] According to DESC witness Bell, if the maximum SSVM for a specific generator over the course of a month is 25% or less, the generator pays no VIC, and if the SSVM is between 25% and 45%, the generator pays half; anything over 45% resulting in no reduction of the VIC.[197]

CCEBA witness Burgess argued that the Commission should not approve DESC's proposed Mitigation Protocols, and objected to the calculation of the SSVM, which is the mechanism via which the protocols measure variability of QF generation.[198] Burgess opined that, rather than comparing output to a prior hour's production, the SSVM should instead compare output to expected production to gauge variability. Although Burgess conceded that the SSVM could be used as a starting point, he also recommended that the Commission reject the protocols in their entirety and simply adopt similar protocols utilized in North Carolina, subject to certain modifications he proposed. [199]

In response, DESC witness Bell noted that DESC could update the Mitigation Protocols, if requested by the Commission, to account for forecasts over each five-minute period calculated within the SSVM, instead of the one-hour lookback.[200] Bell explained that this change would also impose additional obligations onto these generators, such as entering forecasts for each five-minute period into the calculation.[201] Bell stated that not only would these forecasts have to be supplied by the QFs, but they also must meet some threshold accuracy level to be considered in the Mitigation Protocols to prevent QFs from

[196] Tr. Vol 2. pp. 181.13-181.14.
[197] Id.
[198] Tr. Vol. 5 p. 16.32.
[199] Tr. Vol. 5 p. 16.33.
[200] Tr. Vol. 1 p. 181.13.
[201] Id.

gaming the spreadsheet by presenting favorable, but inaccurate, forecasts.[202] As for the other edits proposed by CCEBA witness Burgess, DESC witness Bell noted that the Mitigation Protocols already provide a level of tolerance for the scenarios described by Burgess.[203] Specifically, Bell explained that in order to completely eliminate the VIC applicable to a QF generator, that QF generator does not have to completely eliminate its variability—rather, it simply has to reduce the SSVM below 25%.[204] As for Burgess's suggestion to judge variability from a range broader than each site, DESC witness Bell noted that DESC could aggregate this information for facilities that "are under contract with DESC by the same owner;" however, that owner would have to provide "the aggregated generation meter data and aggregated forecast data in one properly completed SSVM spreadsheet each month."[205]

Responding to witness Burgess's recommendation to adopt certain protocols from North Carolina, Bell explained that this would not alleviate the reserves required to be carried by DESC.[206] The North Carolina protocols look at the average volatility of variable generators, which is not the improvement that will save costs when considering additional reserves.[207] Bell maintained that the Mitigation Protocols are appropriate because they focus on mitigating the largest drops in generation, which are the drops that have to be covered in real-time and, therefore, cause DESC to carry additional operating reserves.[208]

[202] Tr. Vol. 1 p. 181.14.
[203] Id.
[204] Id.
[205] Tr. Vol. 1 p. 181.16.
[206] Tr. Vol. 1 p. 181.17.
[207] Id.
[208] Id.

LEI reviewed the specific disputed items related to the Mitigation Protocols and noted that it "agrees with DESC's proposed mitigation protocol and SSVM calculation, so long as the modifications which Bell noted in his rebuttal testimony are incorporated."[209] LEI noted that these changes include "calculating solar QF production variability relative to forecast rather than actual, as well as allowing solar owners to aggregate production data from across QFs they own."[210] The Commission believes comparing to forecast is a reasonable approach to use at this time.

DESC's proposed SSVM Mitigation Protocols would require QFs to install a revenue quality meter (the integration meter) "capable of recording 5-minute energy production data for the Facility's AC production." Although LEI asserted that the production meter requirement is not "particularly onerous" and "far from a material issue,"[211] the Commission adopts and orders that QFs shall continue to use standard production meters for recording QF generation as required under the Standard Offer/ Form PPA. If DESC has a problem with the necessary data collection, the Company shall present the matter for consideration by the Commission.

The record reveals that these additional reserves correlate to the large, unexpected drops in generation from these QFs. As such, the Mitigation Protocols appropriately align those drops with corresponding reductions in the VIC. Likewise, the Commission finds it appropriate to measure such drops utilizing a percentage mechanism rather than a pure MW measure. The Commission finds that it is reasonable to adopt DESC's proposed

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[209] Hearing Exhibit 13 (LEI Report) p. 74.
[210] Id.
[211] Hearing Exhibit 13 (LEI Report) p. 59.

Mitigation Protocol and SSVM calculation, with the incorporation of the modifications by DESC witness Bell noted in his rebuttal testimony. Bell's modifications include calculating solar QF production variability relative to forecast rather than actual, as well as allowing solar owners to aggregate production data from across the QFs that they own. DESC's proposed SSVM Mitigation Protocol require QFs to install a revenue quality meter (the integration meter) capable of recording 5-minute energy production data for the Facility's AC production.[212] The Commission adopts and orders that QFs shall continue to use standard production meters at this time for recording QF generation as required under the Standard Offer/Form PPA.

a. Two-Day Submission Time for SSVM Spreadsheets

DESC recommends that the current requirement that QFs submit the SSVM spreadsheet to DESC within two (2) business days of the month's end be maintained. CCEBA witness Burgess recommended that the deadline be extended to five (5) days, stating that DESC's proposal was unduly onerous. LEI disagreed that the two-day period was onerous and that the recommendation of CCEBA and CCL/SACE that the deadline be extended to five (5) days be rejected.[213] LEI supported the DESC retention of the current deadline of two (2) business days. The Commission finds that the current requirement that QFs submit the SSVM spreadsheet to DESC within two (2) business days of the month's end be continued.

[212] Tr. Vol. 1, p. 181.14. See also, Tr. Vol. 1 p. 43, and Tr. Vol. 7, p. 92.
[213] Id.

b. Two-Strike Provision

DESC proposes a two-strike disqualification for non-submission of data for the Mitigation Protocol. CCEBA witness Burgess recommends that this provision be removed, asserting that the requirement is unduly onerous. LEI agrees that the two-strike provision is onerous, and asserts that the provision could be harmful to customers, since it could remove the use of the mitigation protocol from application to the VIC by DESC, resulting in a higher VIC charge. LEI asserts that any QFs unable to reduce their VIC would not have incentive to reduce or avoid variations in output.

LEI does not view this additional disqualification provision as necessary and recommends that the Commission reject this element of DESC's proposed Mitigation Protocol. LEI supports removal of the provision, and suggests that, if the Commission believes that a provision is necessary, the Commission should consider a fine or have a penalty structure.[214]

The Commission rejects DESC's proposed two-strike disqualification provision. We agree with LEI and find that the proposal could potentially harm customers, in the sense that any QFs that are disqualified from eligibility for the Mitigation Protocol, and are not able to reduce their monthly VIC, would no longer be incentivized to avoid unexpected variations in output.[215]

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[214] Id.
[215] Id.

c. Modifications to the Standard Offer/Form PPA

(1) Cash Collateral

DESC proposed eliminating cash collateral as an option for providing Performance Assurance under the Standard Offer and Form PPA.[216] DESC witness Folsom explained the concept of "Performance Assurance" in this context and stated that its primary purpose is to "provide additional cost-protection to customers because DESC can draw down upon such Performance Assurance in the event a QF is unable to fulfill its obligations under the Form PPA or Standard Offer."[217] Folsom pointed out that, although this express option to provide cash would be removed, QFs would still be able to select among a number of other options, including a letter of credit, a parental guarantee, and a surety bond.[218] Folsom noted that accepting cash collateral is also problematic from an administrative perspective given that DESC does not accept cash deposits of this nature.[219] However, CCEBA witness Levitas argued that removal of the cash collateral option, along with the revised surety bond, is problematic and that the express cash collateral option should be maintained.[220] Folsom responded that DESC is willing to compromise and maintain the express reference to cash collateral in the PPA given that the parties could utilize cash collateral, regardless of whether it is expressly referenced.[221]

The Commission finds that maintaining the current language in the Form PPA that expressly references cash collateral is appropriate. The Commission also finds that QFs

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[216] Tr. Vol. 3 p. 190.19.
[217] Tr. Vol. 3 p. 190.20.
[218] Id.
[219] Id.
[220] Tr. Vol. 5 p. 216.8.
[221] Tr. Vol. 3 pp.197.3-197.4.

may present other performance assurance mechanisms to DESC, including a letter of credit, surety bond, or parental guarantee.

(2) Environmental Provisions

DESC witness Folsom discussed several changes to the Form PPA and Standard Offer to clarify the scope of coverage and to highlight environmental considerations at issue in these documents.[222] No party expressed disagreement with these proposed changes. The Commission finds that these changes to the Form PPA and Standard Offer are just and reasonable.

(3) Shortfall Report

DESC witness Folsom explained certain revisions to Section 3.5 (Contract Quantity and Guaranteed Energy Production) provision of the Form PPA Agreements.[223] As it stands, Section 3.5 requires QFs to pay liquidated damages to DESC if the QF does not deliver to DESC at least 85% of the amount of energy that the parties agree upon at the time of contracting.[224] DESC witness Kassis cites certain operating issues of these QFs that can contribute to this shortfall.[225] Regardless of the reason, Kassis described that in the event a project experiences a shortfall, DESC still has to provide power to its customers by going to the market to procure replacement power, which may not represent the most economical option for DESC's customers.[226]

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[222] Tr. Vol. 3 p. 192.20.
[223] Tr. Vol. 3 p. 190.21
[224] Id.
[225] Tr. Vol. 1 pp. 20.32-20.33.
[226] Id.

The changes proposed by witness Folsom would maintain these damages and require any QF experiencing "a Shortfall (as defined in the Form PPA and Standard Offer) during any Contract Year (as defined in the Form PPA and Standard Offer) . . . to submit a report to DESC and the ORS detailing the cause of such Shortfall and how it plans to avoid similar Shortfalls going forward."[227] Folsom explained that requiring the report to be submitted to the ORS is appropriate because "its mission is centered upon the 'using and consuming public'—the same customers which the shortfall provision seeks to protect."[228].

No party expressed disagreement with these proposed changes. The Commission finds that these proposed changes are reasonably related to the shortfall report. The Commission also directs DESC to submit the shortfall reports to ORS and to the Commission.

(4) System Disruption Notice

DESC proposes revising references to the system disruption notice in the Form PPA and Standard Offer. DESC witness Folsom testified that the proposed revisions to Section 5.1(a) of the Form PPA and Standard Offer were driven primarily by system safety and reliability.[229] Folsom asserts, if a QFs facility creates "recurring power quality issues or other issues that disrupt normal operation" of DESC's transmission or distribution system, then upon notice from DESC, the QF would have a period of eight (8) months to address and remediate such issues.[230] Witness Kassis cited this experience, in part, as justification

[227] Tr. Vol. 3 at p. 190.21, line 18 – p. 190.22, line 1.
[228] Tr. Vol 3 p. 190.22, lines 4-6.
[229] Tr. Vol. 3 p. 190.22.
[230] Id.

for the modifications to Section 5.1(a) of the Form PPA and Standard Offer to ensure that risks to customers arising from these operating issues are mitigated.[231]

DESC witness Folsom noted that, although the documents do not prescribe the actual remediation measures to be taken in the event of such operating issues, the documents do mandate all such remediation be done in accordance with "Good Utility Practice," as defined in the Form PPA and Standard Offer.[232] No party expressed disagreement with these proposed changes. The Commission finds that DESC's proposed changes are reasonable and are adopted.

(5) Attachment D – Insurance Requirements

DESC witness Folsom presented DESC's proposed changes to the insurance requirements in the Form PPA and the Standard Offer. The following changes to ATTACHMENT D – Insurance Requirements for QFs:

a. Allow DESC to request a certificate of insurance at any time during the term of the agreement, which the QF must then furnish within 20 days;
b. Increase the amount of General Liability insurance coverage to $2,000,000 per occurrence and $4,000,000 in the aggregate that a QF must obtain;
c. Increase the amount of Employer's (QF) liability insurance coverage to $2,000,000 for each accident for

[231] Tr. Vol. 1 p. 20.37
[232] Tr. Vol 3 p. 190.22, line 13.

bodily injury or for each employee for bodily injury by disease;

d. Increase the amount of Environmental Impairment insurance coverage to $2,000,000; and

e. Require Comprehensive Automobile Liability insurance coverage of at least $2,000,000.

DESC witness Folsom explained that the modifications to this exhibit conform with Dominion Energy, Inc.'s requirements for insurance.[233]

In response, CCEBA witness Levitas expressed disagreement over both the "(1) new timing for certificate of insurance delivery, and (2) revised coverage amounts."[234] As for the timing of certificate delivery, he argued that it would give "DESC unfettered discretion to require proof of insurance at any time after a PPA is signed."[235] He asserted that this change would "impose unnecessary costs and burdens on QFs."[236]

DESC witness Folsom responded that this change simply reflects the underlying obligations of the PPA and maintaining insurance is a basic aspect of "developing such a complex and costly facility."[237] Regarding the timing of delivery for insurance certificates, Levitas noted that he found Folsom's responsive testimony "persuasive" and withdrew his

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[233] Dominion Energy South Carolina, Inc., Amended Application to Approve and Establish the Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and all other Appropriate Terms and Conditions, Ex. 6, Attach. D, Docket 2021-88-E (filed June 7, 2021).
[234] Tr. Vol. 5 p. 216.9.
[235] Id.
[236] Tr. Vol. 5 p. 216.10.
[237] Tr. Vol. 3 p. 197.34.

objection to a QF providing proof of and maintaining insurance.[238] No other party expressed disagreement with this proposed change.

Regarding the proposed increases in coverage amounts, Levitas simply described them as "arbitrary," with the net effect of "needlessly discriminating against independent power producers."[239] Folsom noted that CCEBA and DESC appear to agree with the types of coverage required, and only disagree upon the amounts of such coverage.[240] Folsom noted that these increased amounts not only conform to DESC's parent company (Dominion Energy, Inc.), but they also reflect the use of emerging technologies in the industry, which typically increase the insurable value of these projects, while also introducing additional safety concerns.[241] Levitas acknowledged that the addition of certain emerging technologies increases the value of these QFs.[242]

LEI recognized that "the proposed coverage levels are generally obtainable in the marketplace."[243] LEI ultimately recommended that the Commission adopt DESC's increased coverage amounts only for the Form PPA, while maintaining existing coverage amounts for the Standard Offer. LEI provided three (3) examples of coverage limits required by other utilities, which support its recommendation to stagger the insurance coverages, with the increased amounts applying to the larger facilities under the Form PPA.[244]

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[238] Tr. Vol. 5 p. 206, lines 24-25.
[239] Tr. Vol. 5 p. 218.8.
[240] Tr. Vol. 3 p. 197.5.
[241] Id.
[242] Tr. Vol. 5 p. 218.7.
[243] Hearing Exhibit 13 (LEI Report) p. 64.
[244] Id.

DESC witness Folsom noted that LEI also recommended that the Commission increase the coverage amounts in the Form PPA.[245] He explained that these increased coverage amounts "mitigate the risk for DESC's customers, particularly given that [emerging technologies] can present increased costs and potential safety concerns."[246]

The Commission finds with regard to the delivery of the insurance certificate, that DESC shall amend the proposed Form PPA to reference the 20-day requirement for delivery of the insurance certificate. Further, as proposed by LEI, the Commission finds and adopts that DESC shall maintain the insurance coverage amounts in the Standard Offer PPA at current levels, and the proposed higher coverage amounts shall apply only for the Form PPA, which is used with QFs of more than 20 MW.

(6) Attachment F – Form of Surety Bond

DESC also seeks to amend the form of the Surety Bond required in Exhibit F to the Form PPA and Standard Offer. DESC witness Folsom described the justification for the change by asserting that the proposed changes are to further the integration of DESC into the larger Dominion Energy, Inc.[247] The proposed revised paragraph 8 of the proposed Surety Bond Form has two changes to which CCEBA has objected. First, the proposal would change the time for payment upon demand by the Surety to an Obligee from fifteen (15) days to ten (10) days.[248] Further, the same paragraph adds a provision which states:

> Surety shall pay Obligee the amount demanded in freely transferable funds, without defense, reduction, or offset, up to and including the Bond Amount, in accordance with payment instructions set forth in the demand. There shall be

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[245] Tr. Vol. 8 p. 129.
[246] Tr. Vol. 8 p. 1313.
[247] Tr. Vol. 3 p. 190.23.
[248] Tr. Vol. 3 pp. 188 & 337; Hearing Exhibit Nos. 4 & 5 (Exhibits JEF 2 and 3, Attachment F, para. 7.

> no further condition to Surety's obligation to pay Obligee, and Surety expressly waives any right to setoff, cross-claim, or any other claim that Surety or Principal may now have or at any time hereafter may acquire.[249]

Witness Levitas noted that both these changes are different from the bond form previously approved by the Commission in the 2019 proceeding and DESC has provided "no rationale."[250] Levitas stated that, in his experience "providers consider a 10- day payment period to be too short and are often unwilling to execute surety bonds containing such a short payment period."[251] Levitas further objected to the waiver of defenses language noting that "even though the surety may have a legal right under the applicable governing law to assert as defense – such as that the QF did not actually breach the PPA – DESC would force the surety to forego all such legal defenses."[252]

On rebuttal, DESC witness Folsom raised no further defense of the proposed changes. LEI also reviewed the surety bond issue and concluded, "it is LEI's view that modifying forms to conform with parent company practice is not sufficient justification for making a change. Changes should instead respond to a material risk to customers before being proposed."[253] While LEI recommended that any future changes proposed by DESC "be justified first and foremost in response to a material impact to customers," it nevertheless recommended adoption of the Form of Surety Bond proposed by DESC

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[249] Id.
[250] Tr. Vol. 5 p. 216.11.
[251] Id.
[252] Tr. Vol. 5 p. 216.12.
[253] Hearing Exhibit 13 (LEI Report) p. 66.

because "we do not believe that QF developers would be significantly harmed in this instance."[254]

The Commission, having reviewed all of the testimony, exhibits, and arguments submitted on this issue by all Parties, finds that the assertions of LEI are compelling and finds that the material changes to approved Form PPAs and Standard Offers and their attachments should respond to a material risk to customers "before being proposed." The Commission does not, however, agree with LEI that the changes to the Surety Bond form are harmless and therefore immaterial. The Commission finds compelling the testimony of witness Levitas as to the effect of these types of changes to the Surety Bond form on QF developers. The Commission finds that DESC should maintain the existing form of Surety Bonds, based on the testimony of CCEBA witness Levitas. The Commission rejects the Surety Bond changes originally proposed by DESC for QFs.

(7) Ancillary Services

The Parties disagree regarding the definition of "Energy" included in the Proposed Form PPA and Standard Offer. The current definition includes the following language:

> "Energy" shall also include all electrical products produced by or related to the Facility, including spinning reserves, operating reserves, balancing energy, regulation service, ramping capability, reactive power and voltage control, frequency control and other ancillary or essential reliability service products, or any benefit Buyer otherwise would have realized from or related to the Facility if Buyer rather than Seller had constructed, owned or operated the Facility, it being the Parties' intent that all such benefits and entitlements in addition to electrical output that flow to the owner or operator of the Facility, whether existing as of the

[254] Id.

> Effective Date or at any time during the Term, belong to Buyer at no additional cost to Buyer.[255]

Witness Levitas testified that ancillary services are referenced in the Energy Freedom Act.[256] He further quoted S.C. Code Section 58-41-20 which "requires that 'each electric utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electric utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers'. . . ."[257] Because the Form PPA as currently worded would provide that "other ancillary or essential reliability service products . . . belong to the Buyer at no additional cost to Buyer,"[258] Levitas testified that DESC's "avoided cost rates should include the cost of procuring ancillary services that are avoided by virtue of its purchase of 'energy' from QFs under PURPA."[259] Levitas believes the rate proposed by DESC does not do that, and he suggested that "the conveyance of and compensation for reactive power is properly dealt with in the interconnection agreement between the parties and not in the PPA,"[260] because the DESC standard Interconnection Agreement ("IA") "explicitly requires that it pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs outside of a prescribed range required by the IA."[261]

DESC witness Kassis, in his rebuttal testimony, confirmed that:

> Ancillary Services are not included in the calculation of avoided costs. DESC's avoided cost calculation represents

[255] Exhibit 7 to DESC's Second Amended Application, p. 7.
[256] Tr. Vol. 5 p. 216.13, line 1.
[257] Tr. Vol. 5 p. 216.13, lines 1-4.
[258] Tr. Vol. 5 p. 216.13, lines 9-13.
[259] Tr. Vol. 5 p. 216.13, lines 19-21.
[260] Tr. Vol. 5 p. 216.14, lines 1-3.
[261] Tr. Vol. 5 p. 216.14, lines 3-5.

> the energy and capacity avoided by purchasing from the QF. The ability to provide additional services that the grid operator would normally provide would have to be truly avoided in order for the seller to get compensated and the seller would also have to provide specific operating protocol and commitments in a contract which could very well reduce other compensation values. Any decision about a solar QF's ability to even provide ancillary services and only then the value of such services would be fact specific—only capable of being determined on a case-by-case basis by reviewing each renewable generating facility.[262]

Kassis noted that the Interconnection Agreement is generally negotiated by the Transmission Provider while the PPA is negotiated by the generation purchaser, which can be, but is not always, the same entity.[263] He thus recommended maintaining the structure as proposed by DESC. In the case of reactive power, which he described as an ancillary service, "[a]ny decision about a solar QF's ability to even provide ancillary services would . . . be fact specific."[264] The value of any ancillary services are determined on a case-by-case basis, taking into account the specific capabilities of the generating plant.[265] Kassis argued that "there is no need to adopt Witness Levitas' suggestion at this time and, as in the example noted above where DESC is not the party to both the IA and the PPA, it may have unintended negative consequences."[266]

On surrebuttal, Levitas stated that Kassis' testimony was internally inconsistent and "confirmed the need for clarification."[267] He testified that while Kassis confirmed that ancillary services such as reactive power were not included in the calculation of avoided

[262] Tr. Vol. 1 p. 27.11, line 19.
[263] Tr. Vol. 1 pp. 27.12-27.13.
[264] Tr. Vol. 1 p. 27.12, l.4.
[265] Tr. Vol. 1 p. 27.12.
[266] Id.
[267] Tr. Vol. 5 p. 218.12, line 3.

costs, the definition of "Energy" gives such services to DESC "at no additional cost."[268] He argued that, while Kassis may contend that such terms can be separately negotiated based on fact-specific circumstances, the net result is confusing and "runs afoul of Act 62, which requires that the Commission treat small power producers on a 'fair and equal footing with electrical utility-owned resources' by ensuring that avoided cost rates 'fully' reflect the utility's avoided costs with a methodology that 'fairly accounts' for costs avoided, 'including . . . ancillary services.' "[269] Levitas suggests "at a minimum, the Commission should require DESC to remove the language in the PPA purporting to give DESC ancillary services for free."[270]

The testimony of witness Levitas is compelling regarding the language of the definitions in the Form PPA and Standard Offer. Since compensation for ancillary services can be independently negotiated depending on the fact-specific circumstances of a given QF facility, the Commission finds that it is unreasonable for the language in the PPA to require the QF to convey ancillary services to DESC at no additional cost and that DESC hase not justified the inclusion of ancillary services as energy products provided by QFs to DESC free of charge. The Commission further finds that DESC shall remove such language from the definition of Energy in the Form PPA and anywhere else it appears in DESC's proposed forms and documents.

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[268] Tr. Vol. 5 p. 218.12, lines 8-12.
[269] Tr. Vol. 5 p. 218.12, lines 13-17.
[270] Tr. Vol. 5 p. 218.12, lines 19-20.

d. Notice of Commitment Form

Witness Folsom discussed the proposed changes to DESC's Notice of Commitment To Sell Form ("NOC Form"), which was attached as Exhibit 8 to DESC's Amended Application. He described the NOC Form as "a creature of Act 62" which requires that a QF "shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed [NOC Form]."[271] He testified that the NOC Form allows a QF to "lock-in" avoided cost rates in exchange for its "substantial commitment" to sell the electrical output of its facility to the utility.[272] Folsom then explained that the NOC Form operates to establish the Legally Enforceable Obligation ("LEO") under PURPA, a non-contractual but binding statement of intent to sell power generated by a QF.

Witness Levitas agreed that the NOC Form provided a basis for establishment of an LEO. He noted that FERC defined a LEO "by the QF's commitment, and not the utility's actions" to prevent utilities from frustrating the purpose of PURPA through delay and inaction.[273] He stated in his testimony that both PURPA and Act 62 "require this Commission to approve contract and NOC terms and conditions that strike a reasonable balance between the legitimate business interests of the QF and those of the utility in light of generally prevailing practice in the industry."[274] Levitas testified that this standard of "commercial reasonableness" should be applied, and that "[c]ontract terms that make it

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[271] Tr. Vol. 3 p. 190.7.
[272] Id.
[273] Tr. Vol. 5 p. 216.14.
[274] Tr. Vol. 5 p. 216.7.

extremely difficult or impossible to finance QF development do not strike that balance and are discriminatory towards QFs."[275]

Folsom stated that "[t]he NOC Form touches upon issues such as site control, delivery periods, and delivery deadlines as these provisions evidence substantial commitment and are important to ensure that the project is commercially viable and the developer has made a financial commitment to such project."[276] He first addressed the concepts included in the currently approved NOC Form, and then testified to the changes proposed by DESC.

The first substantive proposed change to the NOC Form adds Section 3(ii) to add a category of "Facility Description" for Storage facilities, and sets forth questions related to the type and size of any storage devices included in a facility. Folsom testified that these changes assure that the type of storage facility is consistent with PURPA, and therefore "provide flexibility for developers to utilize storage in a variety of ways within this PURPA framework" and provide DESC with "sufficient information to provide rates that accurately reflect the avoided costs on the DESC system for such QF."[277] CCEBA and other Parties did not challenge the storage language included in the proposed NOC Form.

The second proposed change to the NOC Form discussed by Folsom relates to proof of site control, which Folsom testified was a "fundamental element of substantial commitment."[278] DESC proposed to "modify the NOC Form to require a certification that

[275] Tr. Vol. 5 p. 216.7, lines 11-12.
[276] Tr. Vol. 3 p. 190.9.
[277] Tr. Vol. 3 p. 190.13.
[278] Tr. Vol. 3 p. 190.14.

the QF has at least taken meaningful steps to obtain control of the project site and submitted all applications and filing fees necessary to operate and maintain the project."[279]

In response, Levitas opposed the proposed changes, stating that while site control is a valid prerequisite to formation of an LEO, "readiness to begin construction of a project is not a reasonable or permissible requirement for formation of an LEO."[280] Levitas continued by stating that, because the PPA ultimately "governs the QF's obligations with respect to constructing a facility and placing it in service," readiness for construction "is not germane to formation of an LEO" and the suggested proposed term, which would require readiness to begin construction, should be rejected.[281]

Folsom stated in rebuttal that FERC had authorized such requirements in Order 872.[282] In response to Levitas' testimony and analysis, Folsom stated DESC proposed a new section: "Seller has taken meaningful steps to obtain site control of the Project Site adequate to commence construction of the Facility." He also proposed adding: "The documents attached hereto as Exhibit B establish that Seller has secured – or has submitted all applications and filing fees necessary to secure – all local permitting and zoning approvals for the Project Site necessary to commence construction of the Facility."[283]

In surrebuttal, Levitas noted that construction was irrelevant to the issue of formation of an LEO under PURPA, and preventing formation of an LEO until the "very end of the development cycle" denies QF developers price certainty and "would make it

[279] Tr. Vol. 3 pp. 190.14-190.15.
[280] Tr. Vol. 5 p. 216.16.
[281] Id.
[282] Tr. Vol. 3 pp. 197.8 – 197.9.
[283] Tr. Vol. 3 pp. 197.9 – 197.10.

virtually impossible to incur the substantial development costs required to bring a QF to the point of commencing construction."[284] Levitas further noted the revised language testified to by Folsom did not solve the issues:

> While we appreciate the willingness of DESC to consider alternate language, this proposed revision does nothing to address the problem identified in my testimony: a developer is unlikely to be able to apply for construction-related permits, which requires engineered site layout plans, until shortly before construction commences. Application for such permits is thus not a reasonable test of a QF developer's commitment to selling its output to the utility, which is the operative consideration for LEO formation.[285]

LEI supported maintaining the NOC Form in the form approved in the 2019 Avoided Cost proceeding, with no changes: "we believe that the original language pertaining to site control should be maintained, that no changes be made."[286] The LEI Report stated LEI "believes this requirement is best addressed in the Standard Offer / Form PPA, where it is included already, and as such does not need to be included as a condition to execute the NOC form."[287]

With regard to termination, the Parties agreed to revise proposed Paragraph 8(ii) of the Proposed NOC Form to read:

> If Seller does not execute a PPA for the Facility within the later of (i) 90 business days after the Submittal Date, or (ii) 60 business days after receipt of an executable PPA from the Company, provided, however, that if a final interconnection agreement for the Facility has not been tendered to Seller five business days prior to the expiration of such deadline, the deadline for execution of the PPA shall be the date that

[284] Tr. Vol. 5 p. 10.
[285] Tr. Vol. 5 p. 11.
[286] Tr. Vol. 7 p. 55.
[287] Hearing Exhibit 13 (LEI Report) p. 69.

> is five business days after the date that the final interconnection agreement is tendered to the Seller.[288]

Intervenors did not raise objections to other NOC termination provisions proposed by DESC.

With regard to the NOC Form, the Commission rejects all proposed changes by DESC. The Commission furthers finds that DESC shall keep and maintain the existing NOC Form except with regard to adopting and incorporating the one recommendation raised by CCEBA witness Levitas to the termination clause in Paragraph 8(ii) of the DESC Proposed NOC Form as revised in Hearing Exhibit 5 (Revised Exhibit JEF-1). We do not approve any other changes to the NOC. The Commission agrees with LEI that the existing language, in combination with the requirements of the Standard Offer / Form PPA, are sufficient to ensure that QF projects proceed through construction.

N. Transparency

S.C. Code Ann. Section 58-41-20(J) requires that "[e]ach electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." This provision requires the electrical utility to provide a more thorough and detailed Application in its avoided cost cases. These proceedings are complex, and parties need to have full disclosure and adequate time for review. Given the time constraints and resource limitations that are inherent in complex proceedings such as avoided cost, the Commission finds that in future avoided cost proceedings DESC is required to include in its avoided

[288] Tr. Vol. 3 p. 197.11.

cost application information adequate to ensure that the underlying assumptions, data, and results are available to the parties and the Commission, as required by statute. The Commission specifically requires that DESC file the following information, at a minimum, in its next avoided cost proceeding and in all future avoided cost proceedings:

1. All production cost modeling inputs and outputs, including fuel prices, variable O & M, generating unit operating parameters, load forecasts, hourly avoided cost outputs, and system dispatch data;

2. Quantitative analysis and methodologies, with all inputs and outputs, for designating pricing periods;

3. Resource expansion plans assumed for both avoided energy and avoided capacity calculations;

4. Resource adequacy analyses, with all data inputs and outputs, used to develop avoided capacity rates; and

5. All workpapers used to calculate avoided energy and capacity rates from underlying production cost and capital cost modeling.

VI. FINDINGS OF FACT

Based on the evidence in the record, the Commission makes the following Findings of Fact:

1. It is appropriate for DESC to continue using the Difference in Revenue Requirements methodology to calculate its avoided costs.

2. The Revenue Requirements methodology is one of the generally accepted methods for calculating PURPA avoided energy costs, is used throughout the United

States, and has been previously approved by this Commission in Order Nos. 2016-297, 2018-322(A), and 2019-847.

3. DESC is required to calculate its avoided energy and capacity costs based upon an assumed incremental addition of 66 MW of QF energy that was identified by ORS witness Horii and supported by LEI.

4. The 66 MW capacity change is consistent with DESC's modeled new CT generator.

5. It is reasonable to approve two time periods for DESC as follows:

a. A short-term period of twelve months (i.e., May 2021 to April 2022) shall be used to establish avoided energy costs for PR-1 rates; and

b. to establish avoided energy costs for Standard Offer rates, a long-term period (2022 to 2031) is used, which is broken down into two five-year groupings (2022 to 2026 and 2027 to 2031);a short-term period (May 2021 to April 2022) shall be used to establish avoided energy costs for PR-1 rates; and to establish avoided energy costs for Standard Offer rates, a long-term period (2022 to 2031) is used, which is broken down into two five-year groupings (2022 to 2026 and 2027 to 2031). These proposed short-term and long-term periods are reasonable.

6. For the first three years for forecasting, DESC's use of natural gas futures (as shown by NYMEX) represents the best estimate for costs. Beyond three years, EIA AEO's reference case outlook is preferable for establishing a longer-term gas price outlook.

This blended methodology will provide more accurate natural gas price forecasting for short-term and long-term prices than either method used alone.

7. The eleven energy pricing periods for DESC's Standard Offer non-solar are sufficient for purposes of this proceeding.

8. A single-technology-neutral rate schedule (i.e., DESC's proposed non-solar QF energy rates) is more appropriate than separate rates specific to stand-alone solar QFs.

9. It reasonable to eliminate the period from 11 a.m. to 2 p.m. from the summer on-peak period.

10. For avoided capacity costs, DESC should match the capacity change being assessed and the generating unit size.

11. It is reasonable that DESC to adjust capital and fixed operating and maintenance costs upward as appropriate.

12. We find that the proposed Performance Adjustment Factor (PAF) of 1.05 is not appropriate for this case.

13. It is reasonable to adopt data contained in the U.S. Energy Information Administration's Annual Energy Outlook should be adopted for the capital cost assumptions.

14. A single avoided capacity rate should be adopted.

15. Adjusting the size of the capacity change down to 66 MW, or adjusting the size of the generator up to 100 MW, corrects the mismatch in DESC's methodology and assumptions for capital cost.

16. 2022 should be used as the reference year for the avoided cost calculations.

17. DESC's seasonal allocation should be adopted.

18. The Commission will set a fixed VIC as part of this proceeding and $1.80/MWh for all tranches is a reasonable value for the next two years.

19. DESC's proposed mitigation protocol and SSVM calculation, with the incorporation of the modifications by DESC witness Bell, should be adopted.

20. QFs shall continue to use standard production meters for recording QF generation as required under the Standard Offer/Form PPA, rather than a revenue quality meter.

21. The current submission requirement for the Qualifying Facility operator to file the SSVM spreadsheet within two business days of the month's end shall remain in effect. The two-strike disqualification provision shall not be adopted.

22. With regard to the Standard Offer/Form PPA, cash collateral as an option for Performance Assurance shall continue to be available. The Form PPA shall be amended to reference the 20-day requirement for delivery of the insurance certificate. Insurance coverage amounts in the Standard Offer PPA should be maintained at current levels. The proposed higher coverage amounts shall apply only for the Form PPA used with QFs of more than 20 MW.

23. The existing form of Surety Bond is reasonable.

24. DESC's PPA should not require the QF to convey ancillary services to DESC at no additional cost. DESC should remove the language in the PPA purporting to give DESC ancillary services for free.

25. All DESC proposed changes to the NOC Form should be rejected, except the one change accepting and incorporating the recommendation on the termination clause.

26. With regard to the standard for transparency required by South Carolina law, DESC should file a more thorough and detailed Application in avoided cost cases as outlined in this Order.

VII. CONCLUSIONS OF LAW

In entering its Order in this proceeding, the Commission makes the following conclusions of law based upon the filings, testimony, and exhibits that were received into evidence at the hearing in this proceeding and based on the entire record of these proceeding:

1. The Commission has jurisdiction over this matter pursuant to Act No. 62 and S.C. Code Ann. § 58-41-20.

2. DESC is lawfully before the Commission pursuant to S.C. Code Ann. § 58-41-20 seeking approval of its calculations of avoided costs, its proposed avoided cost methodology, and its proposed Standard Offer, Form PPA, and NOC Form.

3. Act No. 62 requires the Commission to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The Commission also is required to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable

energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina brought about by the consequences of Act No. 62.

4. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer, as adjusted by the terms of this Order: are reasonable and prudent, satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

5. The avoided energy and capacity costs for DESC's proposed Rate PR-1 and Rate PR-Standard Offer, as adjusted by the terms of this Order: are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; are just and reasonable; are nondiscriminatory to small power producers; and reduce the risk placed on the using and consuming public.

6. With the modifications approved by the Commission herein, DESC's proposed Rate PR-1 and Rate PR-Standard Offer, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions, are lawful, just, and reasonable.

7. With the modifications approved by the Commission herein, DESC's proposed avoided cost methodology, as set forth in its Rate PR-Avoided Cost Methodology attached as Exhibit No. 6 (AWR-4) to the direct testimony of Company witness Rooks, is reasonable and prudent; satisfies the requirements of PURPA, FERC's implementing

regulations and guidelines, and Act No. 62; is just and reasonable; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

8. With the modifications approved by the Commission herein, DESC's proposed Form PPA, as reflected in Rate PR-Form PPA attached as Exhibit No. 6 (AWR-8) to the direct testimony of Company witness Rooks, is just and reasonable; is commercially reasonable; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

9. With the modifications approved by the Commission herein, DESC's proposed NOC Form, as reflected in Revised Exhibit No. 5 (Revised JEF-1) to the rebuttal testimony of Company witness Folsom, is just and reasonable; provides small power producers a reasonable period of time from its submittal of the form to execute a PPA; satisfies the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; is nondiscriminatory to small power producers; and reduces the risk placed on the using and consuming public.

10. Pursuant to Order No. 2020-244, the Company should be permitted to (1) true up variable integration costs for the period from the first billing cycle in May 2019 until the first billing cycle for the month after the date of this order and (2) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs in order to reimburse the Company for any such variable integration costs.

VIII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED THAT:

1. DESC shall continue to use the Difference in Revenue Requirements methodology to calculate both the energy component and the capacity component of its avoided costs. The Difference in Revenue Requirements methodology is one of the generally accepted methods for calculating PURPA avoided energy costs, is used throughout the United States, and has been previously approved by this Commission in Order Nos. 2016-297, 2018-322(A), and 2019-847.

2. DESC shall correct the mismatch as identified by ORS witness Horii under the change case used in the avoided capacity cost calculation as supported by ORS witness Horii and third-party consultant expert LEI.

3. DESC shall use two time periods to establish avoided energy costs as follows: The short-term period (May 2021 to April 2022) is used to establish avoided energy costs for PR-1 rates; and to establish avoided energy costs for Standard Offer rates, a long-term period (2022 to 2031) is used, which is broken down into two five-year groupings (2022 to 2026 and 2027 to 2031).

4. For the first three years DESC should forecast natural gas prices using natural gas futures (NYMEX) and beyond three years DESC shall use Energy Information Administration – Annual Energy Outlook's reference case for establishing longer-term gas prices.

5. DESC shall use the eleven energy pricing periods for DESC's Standard Offer non-solar.

6. DESC shall employ the use of a technology-neutral approach for all resources as more appropriate. The Commission further approves the use of a single technology-neutral energy rate schedule (i.e., DESC's proposed non-solar QF energy rates) to be used in place of separate rates specific to standalone solar QFs.

7. DESC shall shift the summer hours of 11:00 a.m. to 2:00 p.m. from the summer peak period to the summer off-peak period. This shift "increases the average summer peak marginal cost and increases the accuracy of the TOU averages by 3% over the entire year." DESC's proposal has a 11:00 a.m. to 11:00 p.m. peak period, but a review of DESC's 2022 hourly energy marginal costs shows that the average summer marginal costs between 11:00 a.m. and 2:00 p.m. are significantly lower than the average costs for the other peak hours.

8. For avoided capacity costs: (i) DESC shall match the capacity change being assessed and the generating unit size; and (ii) capital and fixed operating and maintenance costs shall be adjusted. The Company is to provide updated rates. The Commission declines to adopt the proposed Performance Adjustment Factor (PAF) of 1.05 by CCL/SACE witness Sercy. The Commission further adopts CCL/SACE witness Sercy's and LEI's recommendation using data contained in the US Energy Information Administration's Annual Energy Outlook for the capital cost assumptions. LEI states that "as the EIA's cost assumptions for an aero-CT addition are closest to the 100 MW being assessed, they serve as the best source for avoided capacity calculations." The Commission also adopts the use of a single avoided capacity rate, as a resource's capability to deliver capacity when required should determine its payment regardless of technology type.

9. DESC shall make the following two corrections to its forms: (i) correct the mismatch in DESC's methodology and assumptions for capital cost assumptions noted by ORS witness Horii and LEI to adjust the size of the capacity change down to 66 MW or the size of the generator up to 100 MW; and (ii) correct and use 2022 as the reference year for the avoided cost calculations. DESC's calculations rely upon 2020 as the reference year, which results in an 18% underestimation of the avoided capacity cost.

10. DESC shall utilize the proposed seasonal allocation at this time. However, the Commission directs and orders DESC to assess the value of summer capacity and the value of winter capacity, and DESC must provide more clarity and data substantiation on why it believes summer capacity has little to no value as summer capacity should have value as well.

11. DESC shall utilize a fixed VIC for all Tranches of $1.80/MWh. This is a reasonable value for all newly contracted resources over the next two years and for existing contracts in Tranche 1, which previously used the interim VIC of $0.96/MWh with a true up provision. For all new contracts in Tranche 2 or Tranche 3, DESC shall use the $1.80/MWh. A fixed VIC provides certainty for solar project developers and the Commission is concerned that continuing the interim VIC of $0.96/MWh is risking too much of an unknown cost and rate increase for the ratepayer.

12. With regard to the SSVM, DESC shall use the proposed mitigation protocol and SSVM calculation, as recommended by DESC witness Bell noted in his rebuttal testimony. These modifications include calculating solar QF production variability relative to forecast rather than actual, as well as allowing solar owners to aggregate production data

from across the QFs that they own. The Commission believes comparing to forecast is a reasonable approach, and the established Tranches allow a degree of latitude in terms of facility operations. DESC's proposed SSVM mitigation protocol require QFs to install a revenue quality meter (the integration meter) "capable of recording 5- minute energy production data for the Facility's AC production." However, the Commission adopts and orders that QFs shall continue to use standard production meter for recording QF generation as required under the Standard Offer/Form PPA. If DESC has a problem with the necessary data collection, the Company shall present the matter for consideration by the Commission.

13. DESC shall maintain the current requirement that QFs submit the SSVM spreadsheet to DESC within two (2) business days of the month's end.

14. DESC shall not incorporate a two-strike disqualification provision

15. DESC shall modify and adopt the following changes to its Standard Offer/Form PPA: (i) DESC shall continue to allow cash collateral as an option for providing Performance Assurance; (ii) DESC must amend the proposed Form PPA to reference the 20- day requirement for delivery of the insurance certificate; (iii) DESC shall maintain the insurance coverage amounts in the Standard Offer PPA at current levels, and the proposed higher coverage amounts shall apply only for the Form PPA used with QFs of more than 20 MW; (iv) DESC shall maintain the existing form of Surety Bonds by adopting the testimony of witness Levitas and rejecting the proposed changes of DESC; and (v) DESC's proposal is denied to require the QF to convey ancillary services to DESC

at no additional cost and DESC is ordered to remove the language in the PPA purporting to give DESC ancillary services for free.

16. DESC shall maintain its currently approved NOC Form. The Commission furthers orders that DESC shall keep and maintain the existing NOC Form except with regard to one and only one change adopting and incorporating the recommendation raised by CCEBA witness Levitas relating to the termination clause of the NOC Form. There are no other changes to the NOC Form.

17. For future avoided cost proceedings, DESC is required to provide a more thorough and detailed Application. These proceedings are complex, and parties need to have full disclosure and adequate time for review. Given the time constraints and resource limitations that are inherent in complex proceedings such as avoided cost, in the future, utilities are required to include in their avoided cost application information adequate to ensure the underlying assumptions, data, and results are available to the parties and the Commission, as required by statute. The Commission specifically requires that DESC file, at a minimum, the following information in its next avoided cost proceeding and in all future avoided cost proceedings:

a. All production cost modeling inputs and outputs, including fuel prices, variable O&M, generating unit operating parameters, load forecasts, hourly avoided cost outputs, and system dispatch data;

b. Quantitative analysis and methodologies, with all inputs and outputs, for designating pricing periods;

c. Resource expansion plans assumed for both avoided energy and avoided capacity calculations;

d. Resource adequacy analyses, with all data inputs and outputs, used to develop avoided capacity rates;

e. All workpapers used to calculate avoided energy and capacity rates from underlying production cost and capital cost modeling.

18. The methodologies used by DESC to calculate its avoided energy and capacity costs under PURPA for its proposed Rate PR-1 and Rate PR-Standard Offer as modified by the terms of this Order are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this Order.

19. The avoided energy and capacity costs for DESC's proposed Rate PR-1 as modified by the terms of this Order shall be calculated by DESC and filed with this Commission and served on the parties within ten (10) days of the receipt of this Order. The resulting rates as modified by the terms of this Order are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this Order.

20. The avoided energy and capacity costs for DESC's proposed Rate PR-Standard Offer as modified by the terms of this Order shall be calculated by DESC and filed with the Commission and served on the parties within ten (10) days of receipt of this

Order. The resulting rates as modified by the terms of this Order are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this Order.

21. As modified by the Commission in this Order, Rate PR-1, Rate PR-Standard Offer, Rate PR-Avoided Cost Methodology, Rate PR-Form PPA, and the NOC Form, including the rates, credits, charges, costs, underlying methodologies, and the related terms and conditions are reasonable and prudent; satisfy the requirements of PURPA, FERC's implementing regulations and guidelines, and Act No. 62; and are approved for use on, during, and after the first billing cycle of the month following the date of this Order.

22. DESC is authorized to (i) true up variable integration costs for the period from the first billing cycle in May 2019, until the first billing cycle for the month after the date of this Order, and (ii) deduct these "trued up" costs from future payments made to the solar producers with existing PPAs containing the agreement, in order to reimburse the Company for any such variable integration costs.

23. Within ten (10) days of receipt of this Order, DESC shall file with the Commission and serve copies on the Parties the tariff sheets and rate schedules approved by this Order, which are as follows:

- **a.** Rate PR-1;
- **b.** Rate PR-Avoided Cost Methodology;
- **c.** Rate PR-Standard Offer; and
- **d.** Rate PR-Form PPA

24. The avoided cost and other rates reflected in any such tariff sheets shall be consistent with the components and factors set forth herein. The revised tariffs should be electronically filed in a text searchable PDF format using the Commission's DMS System (https://dms.psc.sc.gov/). An additional copy should be sent via e-mail to etariff@psc.sc.gov to be included in the Commission's ETariff system (https://etariff.psc.sc.gov). DESC shall provide a reconciliation of each tariff rate change approved as a result of this Order to each tariff rate revision filed in the ETariff system. Such reconciliation shall include an explanation of any differences and be submitted separately from the Company's ETariff filing. Each tariff sheet shall contain a reference to this Order and its effective date at the bottom of each page.

25. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Justin T. Williams, Chairman
Public Service Commission of
South Carolina
FOR THE MAJORITY

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Ervin, C., concurring in part and dissenting in part. While I concur with the majority on several points, I strongly disagree with key findings in the majority decision.

I am in full agreement with the decision to require DESC to provide greater transparency and supporting data in all future avoided cost proceedings. Section 58-41-20(J) of the South Carolina Code requires DESC's avoided cost filing to "be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." DESC's application fell short of the requirements established in Act 62, and I concur with the majority that DESC shall be required to provide assumptions and data to the Commission in future proceedings that allow for full and independent review.

I also concur with the majority's findings regarding the DRR methodology to calculate avoided costs, requiring DESC to correct the mismatch under the change case used in the avoided capacity cost calculation, approving both short and long periods to establish avoided energy costs, approving the blended approach to forecast natural gas prices, using a technology-neutral approach to determine energy rates, approving the size of the capacity change, and determinations made regarding the company's forms. However, I respectfully disagree with the majority regarding the following findings:

I. Energy Pricing Periods

The majority approved the eleven energy pricing periods DESC proposed for use in its Standard Offer Agreement with non-solar qualifying facilities. I find the evidence in the record does not support DESC's proposal.

CCL/SACE witness Sercy testified: "neither the company's filings nor its discovery responses clarify how Dominion developed the 11 pricing periods under the standard offer rate."[289] Sercy stated: "It is not possible to determine whether DESC's pricing periods align with DESC's system costs," and "DESC did not provide adequate support for its pricing periods in its application and testimony to allow for independent review and verification of the underlying assumptions, data, and results."[290](Witness Sercy found this absence of information in DESC's filing and testimony especially concerning given the Commission's requirement in Order No. 2019-847 directing DESC to provide additional justification for its pricing periods in future filings.[291]

I agree with Sercy's concerns regarding DESC's lack of support for its analysis. DESC's provision of a heat map to justify its proposal did not provide sufficient justification for its proposal. Witness Sercy testified his review of DESC's heat map reveals "there are numerous instances across the heat map where [the] coloration scheme is inconsistent or unclear."[292] Sercy further opined: "Since the pricing periods are not justified by an objective analysis it appears that the company's methods were highly subjective . . . . [T]here remains no information in this proceeding about what subjective criteria the company used to group the hours into pricing period blocks."[293]

I am concerned with the lack of transparency regarding the Company's methodology to establish the pricing periods, particularly given the Commission's previous order, Order No. 2019-847, from the 2019 avoided cost filing, which states "additional justification for pricing periods should be presented in future filings." I disagree the

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[289] Tr. Vol. 4 p. 48, lines 16-19.
[290] Tr. Vol. 4 p. 60.10, lines 10-13.
[291] Tr. Vol. 4 p. 60.10, lines 13-26.
[292] Tr. Vol. 4 p. 60.11, lines 19-20.
[293] Tr. Vol. 4 p. 51, lines 14,16, 20-23.

evidence in the record supports approval of the eleven energy pricing periods proposed by DESC.

II. Shifting Summer Hours to Off-Peak Period

I disagree with the majority's decision to shift the hours of 11:00 a.m. to 2:00 p.m. from the summer peak period to the summer off-peak period. The proposed peak hours adjustment would disadvantage solar QFs as compared to utility-owned traditional generation. I agree with Sercy's testimony that "[i]n order to treat QFs on a fair and equal footing with utility-owned resources, QFs should be compensated in such a way that allows for a level of unavailability that is reasonably comparable to the level of unavailability of utility-owned resources."[294] I believe, as Sercy testified, "[a]pplying a 'performance adjustment factor' ("PAF") within the avoided capacity rate calculations would accomplish this goal."[295]

III. The Performance Adjustment Factor

I strongly disagree with the decision of the Commission to decline to adopt the proposed PAF of 1.05 recommended by CCL/SACE witness Sercy. I believe DESC should be required to apply a PAF of 1.05 to develop an appropriate avoided capacity rate necessary to put QFs on equal footing with utility-owned resources as required by Act 62. Sercy testified: "DESC's proposal would only compensate QFs at the full avoided capacity rate if they generate during all avoided capacity payment hours. This is not true of utility-owned resources. All technologies are subject to forced outages, and sometimes those

[294] Tr. Vol. 4 p. 60.19, line 22-p. 60.19, line 2.
[295] Tr. Vol. 4 p. 60.19, lines 2-3.

outages occur during peak periods when system capacity is most needed. However, the utility still gets full cost recovery for those resources."[296] Under DESC's current proposed rate, QFs would only receive full capacity payments if they generate power during all avoided capacity payment hours. Utility-owned resources are not held to the same standard, receiving cost recovery despite forced outages. An appropriate PAF would ensure QFs would receive full capacity payment even though they may be unavailable for limited periods of time.

In addition, Sercy noted the Commission "already approved this approach for Duke Energy, finding that a PAF of 1.05 was reasonable and supported the goal within Act 62 of putting QFs on equal footing with utility-owned resources."[297] I agree with witness Sercy and would require DESC to apply a PAF of 1.05 so that the appropriate avoided cost rate would put QFs on equal footing with utility-owned resources pursuant to Act 62.

IV. Seasonal Allocation

DESC proposes to allocate 100% of its capacity value to winter mornings. The majority adopted this allocation; I disagree. We do not have sufficient data to make a specific finding on this matter. Furthermore, DESC's IRP provided data regarding the Company's summer capacity and the Commission's finding here is inconsistent with the IRP. We cannot ignore summer peaks.

CCL/SACE witness Sercy testified: "For the technology-neutral capacity rates, DESC allocates all capacity value to a three-hour period during the winter season without

[296] Tr. Vol. 4 p. 54, lines 10-18.
[297] Tr. Vol. 4 p. 54, line 23-p. 55, line 2.

justification and despite the fact that DESC has experienced more summer peaks in the last decade than winder peaks."[298] Sercy noted "the data shows nothing about how capacity should be allocated across different seasons."[299]

Sercy further testified: "DESC's own calculations . . . show that the DESC system has both a summer and a winter capacity need at the same time."[300] Sercy stated: "DESC's 100 percent winter season capacity allocation is at odds with the load patterns on its system."[301] He contends "the top 1 percent of load hours on the system include a very large number of hours during summer afternoons."[302]

I agree with Sercy that the Commission should require DESC "to design a technology neutral rate using public data that appropriately recognizes the fact that the DESC system sometimes peaks in the summer and sometimes peaks in the winter, and furthermore experiences large numbers of high load hours in the summer months . . . ."[303] Sercy offered an allocation that I find more compelling and accurate than the allocation DESC proposed. Sercy identified the 1% of net load hours, after subtracting 973 MW of solar generation, and used average load values for those top 1% hours to derive a winter allocation of 52% and a summer allocation of 48%.[304]

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[298] Tr. Vol. 4 p. 56, lines 8-12.
[299] Tr. Vol. 4 p. 62.18, lines 20-21.
[300] Tr. Vol. 4 p. 62.19, lines 4-6.
[301] Tr. Vol. 4 p. 57, lines 4-6.
[302] Id, lines 8-9.
[303] Tr. Vol. 4 p. 60.29, lines 9-12.
[304] Tr. Vol. 4 p. 60.29, line 13-p. 60.30, line 21.

LEI recommended "DESC assess the value of summer capacity, and provide more clarity and data substantiation on why it believes summer capacity has little to no value should it reach that conclusion."[305]

I do not agree that DESC's proposal to allocate 100% of its capacity value to winter mornings is reasonable. I would adopt Sercy's recommendation to revise DESC's seasonal capacity allocation and find his recommendation is based on sound analysis and information regarding summer and winter capacity.

V. The Variable Integration Charge

I agree with the majority that it is reasonable to set a fixed VIC. I find that a VIC has inhibited QF development in DESC territory and that S.C. Code Ann. Section 58-41-20(F) requires that a PPA with a fixed integration charge be available to small power producers. However, I disagree as to the amount of the charge determined in this proceeding. DESC did not fully account for its incremental reserve forecast, and therefore, I do not support the LEI recommendation to set the VIC at $1.80/MWh. The VIC proposed by DESC is not supported by the evidence, especially in light of the de minimis cost risk to customers and the disproportionate impact an artificially high integration charge could have for solar development in the state. I find the testimony of CCEBA witness Burgess most compelling and believe a fixed VIC of $0.73/MWh is supported by the evidence in this proceeding.

[305] Hearing Exhibit 13, p. 37.

VI. The Solar Site Variability Metric Mitigation Protocol

I disagree the evidence supports adopting DESC's proposed mitigation protocol and SSVM calculation. I again find the testimony of CCEBA witness Burgess most compelling. Burgess testified he found DESC's analysis was flawed: "I believe there are at least four major flaws in DESC's proposed SSVM calculation methodology, as well as other logistical concerns."[306]

Burgess noted the SSVM should compare actual output to forecasted output.[307] He also asserts the SSVM should capture hours with the greatest potential for a MW drop—not the greatest percentage drop.[308] Burgess contends it would be more accurate to use an average SSVM instead of a maximum.[309] He further believes the SSVM should not be determined by a single facility, but rather, "the relevant [SSVM] metric should be an individual site's contribution to any fleet-wide drops in solar production."[310] Burgess argued the Commission should require DESC to use the Mitigation Protocols it uses in North Carolina.[311]

DESC witness Bell partially agreed with Burgess's suggestions. While Bell contended DESC's SSVM spreadsheet was "numerically fair and operationally practical in its evaluation of generator output," and that the avoided cost rates proposed in this filing

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[306] Tr. Vol. 5 p. 16.32.
[307] Id.
[308] Id.
[309] T. Vol. 5 p. 16.33.
[310] Id
[311] T. Vol. 5 p. 14, line 22-p. 15, line 11.

are accurate as calculated,"[312], he also stated DESC could make modifications to the spreadsheet. Bell agreed DESC "could update the SSVM requirement to include a forecasting provision," and could modify the spreadsheet to compare each five-minute period to forecast instead of the one-hour 'look back.' "[313]. However, Bell, in contrast to Burgess, did not believe DESC should adopt the mitigation protocol used in North Carolina.[314]

The LEI Report recommended adopting DESC's concessions: "LEI agrees with DESC's mitigation protocol and SSVM calculation, so long as the modifications which Mr. Bell noted in his rebuttal testimony are considered."[315]

I agree with witness Burgess; the mitigation protocol proposed by DESC is flawed, and the Commission should reject it. I find it appropriate for DESC to use the mitigation protocol currently used by DESC North Carolina, with the modifications proposed by Burgess, and agreed to, in part, by Bell. Such will provide a more fair and nondiscriminatory option for QFs to mitigate solar integration charges.

[312] Tr. Vol. 2 p. 179, lines 13-17.
[313] Tr. Vol. 2 p. 181.13, lines 15-16, 20-21.
[314] Tr. Vol. 2 p. 181.17, line 3.
[315] Hearing Exhibit 13, p. 58.